

Republic of the Philippines
ENERGY REGULATORY COMMISSION
San Miguel Avenue, Pasig City



RESOLUTION NO. 02, Series of 2018

**A RESOLUTION APPROVING THE PHILIPPINE
DISTRIBUTION CODE (PDC) 2017 EDITION**

WHEREAS, Section 2(b) of the Republic Act No. 9136, also known as the Electric Power Industry Reform Act of 2001, provides the policy objective of the government to ensure the quality, reliability, security and affordability of electric power supply;

WHEREAS, the provision of Section 2.2.1(f) of the Philippine Distribution Code (PDC), the Distribution Management Committee (DMC) is mandated to initiate and coordinate revisions of the PDC and recommend them to the Energy Regulatory Commission (ERC);

WHEREAS, on 27 August 2010, the DMC posted at the ERC website an invitation for interested parties to submit their proposals to amend any provision of the PDC;

WHEREAS, upon gathering proposals to amend the PDC, the DMC evaluated and resolved on 17 May 2011 to submit the initial proposals to the ERC. Another set of proposals were endorsed to the ERC on 20 September 2011;

WHEREAS, the DMC, during its 1st Regular Meeting for 2012, decided to request the ERC the conduct of expository hearings and public consultations on the proposed amendments to the PDC, and the posting of the said proposals at the ERC website;

WHEREAS, upon gathering input from the Distribution Utilities and other entities, through expository hearings and public consultation held on 18 and 24 April 2012 and 29 May 2012, and upon incorporating such input in the proposed amendments, the DMC resolved to endorse to the ERC the proposed amendments on 26 July 2012;

WHEREAS, as instructed by the ERC, the DMC convened meetings with the Grid Management Committee (GMC) to harmonize proposed amendments to the PDC which affect the definitions, operations, requirements and standards provided by the Philippine Grid Code (PGC), then came up with the provisions commonly agreed by both;

WHEREAS, Republic Act No. 9513, otherwise known as the Renewable Energy Act of 2008, aims to promote the development, utilization and commercialization of renewable energy resources. It particularly provides for the establishment of the framework for the development and advancement of renewable energy resources and the development of a strategic program to increase utilization of said resources;

WHEREAS, the DMC deemed appropriate to propose and incorporate in the PDC new standards, policies, requirements and rules issued by the ERC, Department of Energy (DOE), and other authorities to address issues on the developments brought about by the promotion of renewable energy, and open access and retail competition;

WHEREAS, the existing PDC provides for the standards and policies on the conventional embedded generators but does not provide for the technical requirements for the connections and operations of the embedded renewable energy generations. The DMC decided to study on the subject matter and incorporate the outcome in the PDC;

WHEREAS, the complexities of the operations of embedded renewable energy generations required the DMC to request World Bank, through its technical consultant, to provide advice and support in developing the technical standards for the connection requirements, performance, operations and planning for embedded renewable energy generations;

WHEREAS, on 24 February 2015, World Bank granted the DMC's request and selected Mr. Jorge Bircher. It is worthy to note that Mr. Bircher was also engaged by the GMC, as consultant provided by the World Bank, for the study of VRE Generation in the Philippines;

WHEREAS, the Rules Review Subcommittee (RRSC) convened on various dates with Mr. Bircher and other concerned parties in the electric power industry to get input on their knowledge and experience in the operations of conventional embedded generations, including the renewable energy generations, and how they affect the distribution, transmission, generation and market operations;

WHEREAS, the connection and operational requirements for Embedded Generators provide all necessary procedure and standards for utilizing conventional and renewable resources;

WHEREAS, the DMC, during its special meeting held on 12 November 2015, resolved to approve the first draft of the proposed requirements and to request the ERC the conduct of expository hearing and public consultation;

WHEREAS, on 18 December 2015, the ERC approved the posting of the first draft of the proposed connection and operational requirements for Embedded Generators for the stakeholders' comments;

WHEREAS, upon gathering inputs from the Distribution Utilities and other entities, through expository hearings and public consultation held on 02 and 04 February 2016, and upon incorporating such input in the proposed amendments, the DMC resolved to incorporate the draft requirements for Embedded Generators into the PDC 2016 Edition;

WHEREAS, a series of meetings followed to discuss results of each chapter of the PDC 2016 Edition. On 05 October 2016, the RRSC endorsed the final draft of the PDC 2016 Edition to the DMC plenary;

WHEREAS, the DMC during its Regular Meeting last 13 October 2016 resolved to endorse the PDC 2016 Edition to the ERC for its approval;

WHEREAS, after endorsement of the PDC 2016 Edition to the ERC, the DMC received comments from the ERC-ROS and ERC-CAS last 17 January 2017 and 24 January 2017, respectively;

WHEREAS, the DMC, during its various meetings on 19 January and 03 February 2017, discussed and acted upon on the comments received. Adopted comments and recommendations were incorporated in the final draft of PDC 2016 Edition;

WHEREAS, the draft PDC 2016 Edition was posted at the ERC website on 28 March 2017 for final comment by the stakeholders;

WHEREAS, after receiving comments on 21 April 2017, the RRSC convened to discuss the comments from May to July 2017;

WHEREAS, on 25 July 2017, the RRSC endorsed the final draft of the PDC 2016 Edition for approval of the DMC plenary;

WHEREAS, the DMC, during its Regular Meeting last August 2017, approved and resolved to endorse the PDC 2016 Edition for approval of the ERC; and

WHEREAS, on 25 August 2017, the DMC submitted the final draft of the proposed “**Philippine Distribution Code 2017 Edition**” to the ERC for its approval.

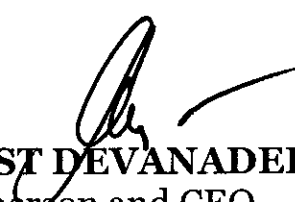
NOW, THEREFORE, the ERC hereby **RESOLVES** to **APPROVE** and **ADOPT**, without prejudice to any issuances by the Department of Energy (DOE) on policy regarding Embedded Generators, the “**Philippine Distribution Code 2017 Edition**”; attached hereto and made integral part hereof as **Annex “A”**.

RESOLVED FURTHER, that the “**PDC 2017 Edition**” shall take effect fifteen (15) days after its publication in a newspaper of general circulation or in the Official Gazette.

Let copies of this Resolution be furnished the University of the Philippines Law Center-Office of the National Administrative Register (UPLC-ONAR) and all Distribution Utilities (DUs).

SO ORDERED.

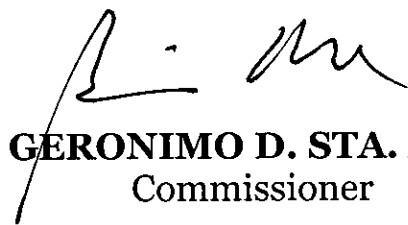
Pasig City, February 27, 2018.


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ROS-SCMD/REM/LLG/FBD

PHILIPPINE DISTRIBUTION CODE
2017 EDITION

December 2017

FOREWORD

As the Philippine economy continues to grow, the demand for sufficient, stable, safe and reliable supply of electricity by business industries and households steadily increases. It is imperative that as the country expands its power generation capacity both in terms of renewable and non-renewable energy sources, the development, operation and maintenance of electric power distribution facilities meet the technical standards, rules and regulations to ensure a safe, reliable and efficient Distribution System in the country.

The Philippine Distribution Code (PDC) 2017 Edition is the result of several years of technical review, analysis, and coordination work among the members and technical staff of the Distribution Management Committee, Inc. (DMC), in close collaboration with the stakeholders of the power distribution sector and guidance of the Energy Regulatory Commission (ERC). In the exercise of its mandate “to initiate and coordinate revisions of the Philippine Distribution Code and make recommendations to the Energy Regulatory Commission” (Section 2.2.1 (e), PDC 2001), the Distribution Management Committee, Inc. (DMC) initiated the review of the PDC in 2010 and invited Users of the Distribution System to propose amendments to the PDC. A thorough evaluation by the DMC and expository hearings and public consultations with stakeholders were then conducted in Luzon, Visayas and Mindanao.

Moreover, with a vision of establishing an up-to-date set of national technical standards and guidelines that will serve as national code for Users of the Distribution System, the PDC 2017 Edition has taken into account the adoption in the Philippines of new and emerging technologies including Variable Renewable Energy (VRE), as well as best practices and experiences of foreign jurisdictions in the use of these technologies. This latest edition has been harmonized with related provisions of the Philippine Grid Code 2016 Edition, the Market Rules of the Wholesale Electricity Spot Market, and subsequent rules and guidelines issued by the ERC applicable to Distribution Systems.

On February 27, 2018, ERC Resolution No. 2, Series of 2018 was issued by the ERC approving the Philippine Distribution Code 2017 Edition, with the following salient features:

- (a) Connection and operational requirements for Embedded Generating plants, conventional or variable renewable energy source, are established;
- (b) The embedded generating plants are classified as large conventional, large VRE, medium, intermediate, small and micro Embedded Generating Plants according to their characteristics and installed capacity;
- (c) Procedures for new connection and modifications of existing connection are specified to guide prospective project proponents in connecting to the distribution system;
- (d) Restructuring of Chapter 7: Revenue Metering Requirements;
- (e) Restructuring of the Distribution Management Subcommittees;

- (f) Representation from the largest Distribution Utility and the Market Operator was added to the Distribution Management Committee;
- (g) Addition of Derogatory Provisions in Chapter 1: Philippine Distribution Code General Conditions;
- (h) Inclusion of “Customer Average Interruption Duration Index” or CAIDI in the Distribution Reliability Indices imposed upon all Distribution Utilities;
- (i) Deletion of the section on “Distribution Code Dispute Resolution”, and inclusion of a new section entitled “Application and Interpretation of Distribution Code Provisions”;
- (j) Deletion of the provision setting separate caps for Technical and Non-Technical Losses and giving the discretion to the ERC to decide and implement limits on losses;
- (k) Application of the PDC to “entities duly authorized to operate a distribution system within Economic Zones”;
- (l) Chapter 4: Financial and Capability Standards for Distribution and Supply is transferred as an Appendix to the PDC;
- (m) References to “Grid Owner” has been replaced with “Transmission Network Provider”;
- (n) Inclusion and definition of new terms; and
- (o) Inclusion of Section 33 of the Republic Act No. 7920 known as the “New Electrical Engineering Law” and any amendments thereto as an additional compliance in the PDC 2017 Edition.

Henceforth, all Distribution Utilities, Embedded Generation Companies, Metering Service Providers and other Users of the Distribution System must secure a copy of the PDC 2017 Edition and are directed to use the PDC 2017 Edition as primary reference and national code in developing, operating and maintaining new and existing Distribution Systems. All Users of the Distribution System must comply with the technical specifications, performance standards and other requirements of the PDC 2017 Edition and shall submit to the ERC, through the DMC, within the periods provided in Chapter 8, a Compliance Report to the PDC 2017 Edition, following the requirements set forth in the PDC, and procedures under the DMC Rules to Govern the Monitoring of Compliance of Distribution Utilities to the PDC. Any claim or request for exemption from compliance with the requirements and standards of the PDC 2017 Edition must be applied with and approved by the ERC, through the DMC, at the soonest possible time for appropriate action.

PHILIPPINE DISTRIBUTION CODE 2017 EDITION

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CHAPTER 1

PHILIPPINE DISTRIBUTION CODE GENERAL CONDITIONS

1.1 PURPOSE

- (a) To establish regulatory framework for the promulgation and enforcement of the Philippine Distribution Code;
- (b) To specify the general rules pertaining to data and notices that apply to all Chapters of the Philippine Distribution Code;
- (c) To specify the rules for interpreting the provisions of the Philippine Distribution Code; and
- (d) To define the common and significant terms and abbreviations used in the Philippine Distribution Code.

1.2 AUTHORITY AND APPLICABILITY

1.2.1 Authority

The Act provides the Energy Regulatory Commission (ERC) the authority to promulgate the Philippine Distribution Code.

1.2.2 Applicability

The Philippine Distribution Code applies to all Users of the Distribution System, unless provided otherwise in a particular Chapter or Article, including:

- (a) Distribution Utilities;
- (b) Other Distribution Utilities connected to Distribution Systems;
- (c) System Operator;
- (d) Embedded Generation Companies;
- (e) Metering Service Providers;
- (f) Suppliers;
- (g) Entities duly authorized to operate a Distribution System within the Economic Zones;
- (h) Other duly authorized entities engaged in the Distribution of Electricity; and
- (i) End-Users.

1.3 ENFORCEMENT AND SUSPENSION OF PROVISIONS

1.3.1 Enforcement

1.3.1.1 The Act assigns to the ERC the responsibility of enforcing the Philippine Distribution Code.

1.3.1.2 The ERC established the Distribution Management Committee (DMC) to monitor the Philippine Distribution Code compliance at the planning and operations level and to submit regular and special reports pertaining to distribution planning and operations.

- 1.3.1.3 The DMC shall initiate an enforcement process for any perceived violations of the Philippine Distribution Code provisions and recommend to the ERC the appropriate fines and penalties for such violations.

1.3.2 Suspension of Provisions

Any provision of the Philippine Distribution Code may be suspended, in whole or in part, when the Grid is not operating in the Normal State and the System Operator has issued an Alert Warning to the Distribution Utility, or pursuant to any directive given by the ERC or the appropriate government agency.

1.4 DEROGATIONS

1.4.1 Applicability

- 1.4.1.1 If a User finds that it is, or will be unable to comply with any provision of the Philippine Distribution Code, then it shall, without delay, report such non-compliance to the ERC, through the DMC, and shall make such reasonable efforts as are required to correct such non-compliance as soon as reasonably practicable.
- 1.4.1.2 When a User believes either that it would be unreasonable to require it to correct non-compliance, the User shall promptly submit to the ERC, through the DMC, a request for derogation from such provision.

1.4.2 Request for Derogation

- 1.4.2.1 A request by a User for derogation from any provision of the Philippine Distribution Code shall contain:
- (a) Sections and provisions of the Philippine Distribution Code against which the non-compliance or predicted non-compliance was identified;
 - (b) The reason or rationale for the non-compliance or expected non-compliance;
 - (c) Proposed corrective actions, if any; and
 - (d) The date of completion by which compliance could be achieved (if corrective actions of the non-compliance is possible).
- 1.4.2.2 On receipt of any request for derogation, the DMC shall promptly review such request, provided that it considers that the grounds for the derogation are reasonable or sufficiently justified. The ERC, based on DMC's recommendation, shall decide on such derogation.
- 1.4.2.3 To the extent of any derogation granted in accordance with 1.4.2.2, the User, as the case may be, shall be relieved from any obligation to comply with the applicable provision of the Philippine Distribution Code and shall not be liable for failure to so comply, but shall comply with any alternative provisions identified in the derogation.
- 1.4.2.4 The DMC shall:
- (a) Keep a register of all requests for derogations, including those denied and those which have been granted, and in the latter case, identifying the name of the person and User in respect of whom the derogation has been granted, the relevant provision of the Philippine Distribution Code and the period of the derogation; and

(b) On request from any User, provide a copy of such register of derogations to such requesting party.

1.4.2.5 The ERC may on its own initiative or at the request of the DMC or a User:

(a) Review any existing derogations; and

(b) Review any derogation under consideration, and establish whether the ERC considers such request as justified.

1.5 DATA, NOTICES, AND CONFIDENTIALITY

1.5.1 Data and Notices

1.5.1.1 The submission of any data under the Philippine Distribution Code shall be done through electronic format or such format prescribed/required by the DMC and agreed upon by the concerned parties.

1.5.1.2 Written notices under the Philippine Distribution Code shall be served by hand delivery, registered first-class mail, or facsimile transfer.

1.5.2 Confidentiality

1.5.2.1 Data submitted by any User to the Distribution Utility in compliance with the data requirements of the Philippine Distribution Code shall be treated by the Distribution Utility as confidential. These include data requirements for connection to the Distribution System and those that are required in the planning, operation, and maintenance of the Distribution System.

1.5.2.2 Aggregate data shall be made available by the Distribution Utility when requested by a User. These data shall be used only for the purpose specified in the request and shall be treated by the User as confidential.

1.6 CONSTRUCTION OF REFERENCES

1.6.1 References

Unless the context otherwise requires, any references to a particular Chapter, Article, Section, Subsection, or Appendix of the Philippine Distribution Code shall be applicable only to that Chapter, Article, Section, Subsection, or Appendix to which the reference is made.

1.6.2 Cross-Reference

A cross-reference to another document shall not in any way impose any condition or modify the material contained in the document where such cross-reference is made.

1.6.3 Definitions

Terms which are capitalized shall be interpreted in accordance with the definitions under Article 1.7. When a word or phrase that is defined in Article 1.7 is more particularly defined in another Article, Section, or Subsection, the particular definition in that Article, Section, or Subsection shall prevail if there is any inconsistency.

1.6.4 Foreword, Table of Contents, and Titles

The Foreword was added to present the historical background of the Philippine Distribution Code 2017 Edition and highlight the significant changes introduced therein. The Table of Contents and the titles were added as a guide for the convenience of the users of the Philippine Distribution Code. The Foreword, the Table of Contents, and the titles of the Chapters, Articles, and Sections shall be ignored in interpreting the Philippine Distribution Code provisions.

1.6.5 Mandatory Provisions

The word “shall” refers to a rule, procedure, requirement, or any provision of the Philippine Distribution Code that requires mandatory compliance.

1.6.6 Singularity and Plurality

In interpreting any provision of the Philippine Distribution Code and unless otherwise specified, the singular shall include the plural, and vice versa.

1.6.7 Gender

Any reference to a gender shall include all other genders. Any reference to a person or entity shall include an individual, partnership, company, corporation, association, organization, institution, and other similar groups.

1.6.8 “Include” and “Including”

The use of the word “include” or “including” to cite an enumeration shall not impose any restriction on the generality of the preceding words.

1.6.9 “Written” and “In Writing”

The words “written” and “in writing” refer to the hardcopy of a document that is generally produced by typing, printing, or other methods of reproducing words in a legible format.

1.6.10 Repealing Clause

All existing rules and regulations, orders, resolutions, and other similar issuances, or parts thereof, which are inconsistent with the provisions of the Philippine Distribution Code 2017 Edition and its appendices are hereby repealed or modified accordingly.

1.7 DEFINITIONS

In the Philippine Distribution Code the following words and phrases shall, unless more particularly defined in an Article, Section, or Subsection of the Philippine Distribution Code, have the following meanings:

Accountable Person. A person who has been duly authorized by the Distribution Utility (or User) to sign the Fixed Asset Boundary Documents on behalf of the Distribution Utility (or User).

Act. Republic Act No. 9136 also known as the “*Electric Power Industry Reform Act of 2001*,” which mandated the restructuring of the electricity industry, the privatization of the National Power Corporation, and the institution of reforms, including the promulgation of the Philippine Grid Code and the Philippine Distribution Code.

Active Energy. The integral of the Active Power with respect to time, measured in Watt-hour (Wh) or multiples thereof. Unless otherwise qualified, the term "Energy" refers to Active Energy.

Active Power. The time average of the instantaneous power over one period of the electrical wave, measured in Watts (W) or multiples thereof. For AC circuits or systems, it is the product of the root-mean-square (RMS) or effective value of the voltage and the RMS value of the in-phase component of the current. In a three-phase systems, it is the sum of the Active Power of the individual phases.

Adverse Weather. A weather condition that results in abnormally high rate of Forced Outages for exposed Components while such condition persists, but does not qualify as a Major Storm Disaster. An Adverse Weather condition can be defined for a particular System by selecting the proper values and combinations of the weather conditions reported by the weather bureau including thunderstorm, wind velocity, precipitation, and temperature.

Alert Warning. A notice issued by the System Operator, including Yellow Alert, Blue Alert, and Red Alert, to notify the Users of the Grid that an alert state exists.

Amended Connection Agreement. An agreement between a User and the Distribution Utility, which specifies the terms and conditions pertaining to the renovation or modification of the User System or Equipment at an existing Connection Point in the Distribution System.

Ancillary Service. Support services such as Primary Reserve, Secondary Reserve, Tertiary Reserve, Reactive Power support, and Black Start Capability which are necessary to support the transmission capacity and Energy that are essential in maintaining Power Quality and the Reliability of the Grid or as defined in the latest edition of the Philippine Grid Code.

Apparent Power. The product of the root-mean-square (RMS) or effective value of the current and the root-mean-square value of the voltage. For AC circuits or systems, it is the square root of the sum of the squares of the Active Power and Reactive Power, measured in volt-ampere (VA) or multiples thereof.

Automatic Generation Control (AGC). It is an Equipment that automatically adjusts the generation to maintain its generation Dispatch, interchange schedule plus its share of Frequency regulation. AGC is a combination of Secondary Control for a Control Area /Control Block and real-time operation of the generation Dispatch function (based on generation scheduling). Secondary Control is operated by the System Operator while generation scheduling is operated by the respective Generation Companies.

Automatic Load Dropping (ALD). The process of automatically and deliberately removing pre-selected Loads from a power System in response to an abnormal condition in order to maintain the integrity of the System. It can be classified as: 1) Under-frequency Load Shedding (UFLS); and 2) Under-voltage Load Shedding (UVLS).

Backup Protection. A form of protection that operates independently of the specified Components in the primary protection system. It may duplicate the primary protection or may be intended to operate only if the primary protection fails or is temporarily out of service.

Black Start. The process of recovery from Total System Blackout using a Generating Unit with the capability to start and synchronize with the System without an external power supply.

Central Dispatch. The process of scheduling generation facilities and issuing Dispatch Instructions to industry participants, considering the energy demand,

operating reserve requirements, Security constraints, Outages and other contingency plans, to achieve an economic operation while maintaining Power Quality, Stability, and the Reliability and Security of the Grid.

Circuit Breaker. A mechanical switching device, which is capable of making, carrying, and breaking current under normal circuit conditions and also capable of making, carrying for a specified time and breaking current under specified abnormal circuit conditions, such as a short circuit.

Committed Project Planning Data. The data pertaining to a User Development once the offer for a Connection Agreement or an Amended Connection Agreement is accepted.

Completion Date. The date, specified in the Connection Agreement or Amended Connection Agreement, when the User Development is scheduled to be completed and be ready for connection to the Distribution System.

Component. A piece of equipment, a line or circuit, a section of line or circuit, or a group of items, which is viewed as an entity for a specific purpose.

Connected Project Planning Data. The data which replaces the estimated values that were assumed for planning purposes, with validated actual values and updated estimates for the future and by updated forecasts, in the case of forecast data.

Connection Agreement. An agreement between a User and the Distribution Utility, which specifies the terms and conditions pertaining to the connection of the User System or Equipment to a new Connection Point in the Distribution System.

Connection Point. The point of connection of the User System or Equipment to the Distribution System (for Users of the Distribution System) or to the Grid (for Users of the Grid).

Connection Point Drawings. The drawings prepared for each Connection Point, which indicate the Equipment layout, common protection and control, and auxiliaries at the Connection Point.

Control Center. A facility used for monitoring and controlling the operation of the Grid, Distribution System, or a User System.

Conventional Generating Facility. Any Generating Unit/Plant which is not a Variable Renewable Energy Generating Facility.

Conventional Generation Company. Refers to a Generation Company that is authorized by the ERC to operate a facility used in the Generation of Electricity which is not a Variable Renewable Energy Generating Facility.

Current Transformer. An instrument transformer intended to have its primary winding connected in series with the conductor carrying the current to be measured or controlled.

Customer. Any person or entity supplied with electric service under a contract with a Distribution Utility or Supplier.

Customer Average Interruption Duration Index (CAIDI). Represents the average time required to restore service.

Customer Demand Management. The reduction in the Supply of Electricity to a consumer of electricity or the disconnection of a Customer in a manner agreed upon for commercial purposes, between a Customer and its Generation Company, Distribution Utility, or Supplier.

Customer Rating Approach. The process of evaluating a Distribution Utility's (or Supplier's) Customer Service Program by using a statistically valid Transactions Survey.

- Customer Self-Generating Plant.** A Customer with one or more Generating Units not subject to Central Dispatch, to the extent that it operates exclusively to supply all or part of its own electricity requirements, and does not export electrical power using the Distribution System.
- Customer Services.** The day-to-day transactions between a Distribution Utility (or Supplier) and its Customers including payment of bills, application for connection, and Customer complaints. It also includes any activity that the Distribution Utility (or Supplier) does to add value or efficiency to these transactions.
- Customer Service Program.** The totality of the Customer Services offered by a Distribution Utility (or Supplier).
- Customer Service Standards.** A listing of Customer Services that measure how effectively a Distribution Utility (or Supplier) conducts its day-to-day transactions with its Customers. Customer Service Standards are intended to ensure customer satisfaction.
- Declared Data.** The data provided by the Generation Company in accordance with the latest/current Generating Unit parameters.
- Dedicated Feeder.** A feeder utilized by a single User, either a Customer or an Embedded Generation Company.
- Degradation of the Distribution System.** A condition resulting from a User Development or a Distribution System expansion project that has a Material Effect on the Distribution System or the System of other Users and which can be verified through Distribution Impact Studies.
- Demand.** The average value of power or a related quantity over a specified interval of time. Demand is expressed in kilowatts (kW), kilovolt-amperes (kVA), kilovolt-amperes reactive (KVAR), or other suitable units.
- Demand Control.** A reduction in Demand for the control of the Frequency when the Grid is in the Emergency State. This includes Automatic Load Dropping, Manual Load Dropping, reduction in Demand upon instruction by the System Operator, and Voluntary Load Management.
- Demand Control Imminent Warning.** A warning from the System Operator, not preceded by any other warning, which is issued when a reduction in Demand is expected within the next 30 minutes.
- Demand Forecast.** An estimate of the future system peak Demand expressed in kilowatts (kW) or megawatts (MW) of a particular Connection Point in the Distribution System.
- Department of Energy (DOE).** The government agency created pursuant to Republic Act No. 7638 which is provided with the additional mandate under the Act of supervising the restructuring of the electricity industry, developing policies and procedures, formulating and implementing programs, and promoting a system of incentives that will encourage private sector investments and reforms in the electricity industry and ensuring an adequate and reliable Supply of Electricity.
- Detailed Planning Data.** Additional data, which the Distribution Utility requires, for the conduct of a more accurate Distribution System planning study.
- Disconnection.** The opening of an electrical circuit to isolate an electrical System or Equipment from a power source.
- Dispatch.** The process of apportioning the total Demand of the Grid through the issuance of Dispatch Instructions to the Scheduled Generating Units and the Generating Units providing Ancillary Services in order to achieve the operational

requirements of balancing Demand with generation that will ensure the Security of the Grid.

Dispatch Instruction. Refers to the instruction issued by the System Operator to the Generation Companies with Scheduled Generating Units and the Generation Companies whose Generating Units will provide Ancillary Services to implement the final Dispatch Schedule in real time.

Dispatch Schedule. The target loading levels in megawatts (MW) for each Scheduled Generating Unit or scheduled loads and for each reserve facility for the end of that trading interval determined by the Market Operator through the use of a market dispatch optimization model.

Dispatch Scheduling and Dispatch Parameters. Refers to the technical data pertaining to the Scheduled Generating Units, which are taken into account in the preparation of the Dispatch Schedule.

Distribution Development Plan (DDP). The expansion, reinforcement and rehabilitation program of the Distribution System which is prepared by the Distribution Utility and submitted to the DOE for integration with the PDP and PEP. In the case of Electric Cooperatives, such plans shall be submitted through the NEA for review and consolidation.

Distribution Impact Studies. A set of technical studies which are used to assess the possible effects of a proposed expansion, reinforcement, or modification of the Distribution System or a User Development and to evaluate Significant Incidents.

Distribution of Electricity. The conveyance of electric power by a Distribution Utility through its Distribution System.

Distribution System. The system of wires and associated facilities belonging to a franchised Distribution Utility, extending between the delivery points on the transmission, sub-transmission system, or generating plant connection and the point of connection to the premises of the End-User.

Distribution Utility. Refers to any Electric Cooperative, private corporation, government-owned utility, or existing local government unit, which has an exclusive franchise to operate a Distribution System in accordance with its franchise and the Act.

Distribution Utility Use. Refers to the Energy used in the proper operation of the Distribution System.

Economic Zone (EZ). Selected areas which are being developed into agro-industrial, industrial, tourist, recreational, commercial, banking, investment and financial centers. An EZ may refer but not limited to any of the following: Industrial Estates (IEs), Export Processing Zones (EPZs), Free Trade Zones (FTZs), Information Technology Parks and Tourist/Recreational Centers, such as those managed, administered, or operated by the Bases Conversion Development Authority (BCDA), Cagayan Economic Zone Authority (CEZA), Clark Development Corporation (CDC), Philippine Economic Zone Authority (PEZA), Phividec Industrial Authority (PIA), and Zamboanga City Economic Zone Authority (ZCEZA).

Electric Cooperative. A cooperative or corporation authorized to provide electric services pursuant to Presidential Decree No. 269, as amended, and Republic Act No. 6938 within the framework of the national rural electrification plan.

Electrical Diagram. A schematic representation using standard electrical symbols, which shows the connection of Equipment or power system Components to each other or to external circuits.

Embedded Generating Plant. The same meaning as Embedded Generators.

Embedded Generating Unit. A Generating Unit within an Embedded Generating Plant.

Embedded Generation Company. A person or entity that generates electricity using an Embedded Generating Unit. Embedded Generation Company shall also include Net Metering customers and customers with self-generating plant.

Embedded Generator. Refers to Generating Units that are indirectly connected to the Grid through the Distribution Utilities' lines or industrial Generation Facilities that are synchronized with the Grid.

Emergency State. The Grid operating condition when either a Single Outage Contingency or a Multiple Outage Contingency has occurred without resulting in Total System Blackout, but there is generation deficiency or Operating Margin is zero, grid transmission voltage is outside the limits of $\pm 10\%$ of the nominal value; or the loading level of any transmission line or substation Equipment is above 115% of its Operational Thermal Limit Capacity exists or as defined in the latest edition of the Philippine Grid Code.

End-User. Any person or entity requiring the supply and delivery of electricity for its own use.

Energy. Amount of work that the system is capable of doing. Generally, it refers to electrical energy and is measured in kilowatt-hours (kWh).

Energy Forecast. An estimate of the future system energy requirement expressed in kilowatt-hours (kWh) or megawatt-hours (MWh) related to each Connection Point in the Distribution System.

Energy Regulatory Commission (ERC). The independent, quasi-judicial regulatory body created pursuant to Republic Act No. 9136, which is mandated to promote competition, encourage market development, ensure customer choice, and penalize abuse of market power in the restructured electricity industry and among other functions, promulgate and enforce the Philippine Grid Code and the Philippine Distribution Code.

EPC Contractor. A company contracted by the Generation Company to carry out the engineering, procurement and construction (EPC) works of a Conventional or VRE Generating Facility.

Equipment. All apparatus, machines, conductors, etc., used as part of, or in connection with, an electrical installation.

Equipment Identification. The system of numbering or nomenclature for the identification of Equipment at the Connection Points in the Distribution System.

Event. An unscheduled or unplanned occurrence of an abrupt change or disturbance in a power system due to fault, equipment outage, Adverse Weather condition, or natural phenomenon.

Fast Start. The capability of a Generating Unit or Generating Plant to start and synchronize with the Grid within 15 minutes.

Fault Clearance Time. The time interval from fault inception until the end of the arc extinction by the Circuit Breaker.

Fault Level. The expected current, expressed in kiloampere (kA) or in megavolt-ampere (MVA), that will flow into a short circuit at a specified point on the Grid, Distribution System, or any User System.

Fixed Asset Boundary Document. A document containing information and which defines the ownership and/or operational responsibilities for the Equipment at the Connection Point.

- Flicker.** The impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time.
- Forced Outage.** An Outage that results from emergency conditions directly associated with a Component requiring that it be taken out of service immediately, either automatically or as soon as switching operations can be performed. Also, an Outage caused by human error or the improper operation of Equipment.
- Franchise Area.** A geographical area assigned or granted to a Distribution Utility for the Distribution of Electricity.
- Frequency.** The number of complete cycles of a sinusoidal variation per unit time, usually measured in cycle per second or Hertz.
- Frequency Variation.** The deviation of the fundamental system frequency from its nominal value.
- Generating Plant.** A facility, consisting of one or more Generating Units, where electric energy is produced from some other form of Energy by means of a suitable apparatus.
- Generating Unit.** A conversion apparatus including auxiliaries and associated Equipment, functioning as a single unit, which is used to produce electric energy from some other form of energy.
- Generation Company.** A person or entity authorized by the ERC to operate a facility used in the Generation of Electricity.
- Generation of Electricity.** The production of electricity by a Generation Company.
- Governor Control.** It refers to the “unblocked” turbine speed governor control of a generating unit.
- Grid.** The High Voltage backbone System of interconnected transmission lines, substations, and related facilities, located in each of Luzon, Visayas, and Mindanao, or as may be determined by the ERC in accordance with Section 45 of the Act.
- Grounding.** A conducting connection by which an electrical circuit or Equipment is connected to earth or to some conducting body of relatively large extent that serves as ground.
- Guaranteed Standards.** Refer to the Customer Services that will penalize a Distribution Utility (or Supplier) for failure to provide the required level of service by making payment to affected Customers.
- Harmonics.** Sinusoidal voltages and currents having Frequencies that are integral multiples of the fundamental Frequency.
- High Voltage (HV).** A voltage level exceeding 34.5 kV up to 230 kV.
- IEC Standard.** The international standard for electro-technical Equipment approved and published by the International Electrotechnical Commission.
- Implementing Safety Coordinator.** The Safety Coordinator assigned by the Distribution Utility (or the User) to establish the requested Safety Precautions in the User System (or the Distribution System).
- Installed Capacity.** Expressed in megawatts (MW) or kilowatts (kW), it refers to the sum of rated generating capacity of each Generating Unit.
- Interruption.** The loss of service to a Customer or a group of Customers or other facilities. An Interruption is the result of one or more component outages.
- Island Grid.** A Generating Plant or a group of Generating Plants and its associated Load, which is isolated from the rest of the Grid but is capable of generating and

maintaining a stable supply of electricity to the Customers within the isolated area.

Isolation. The electrical separation of a part or Component from the rest of the electrical system to ensure safety when that part or Component is to be maintained or when electric service is not required.

Large Customer. A Customer with a demand of at least 1 MW or the threshold value specified by the ERC. Threshold value other than one 1 MW shall be reported by the Distribution Utility to the ERC within 60 days from the effectivity of the revised Philippine Distribution Code.

Large Embedded Generation Company. A Generation Company whose generating facility at the Connection Point has an aggregate Installed Capacity of 10 MW or more.

Load. An entity or an electrical equipment that consumes or draws electrical energy.

Local Safety Instructions. A set of instructions regarding the Safety Precautions on MV or HV Equipment to ensure the safety of personnel carrying out work or testing on the Distribution System or the User System.

Long Duration Voltage Variation. A variation of the RMS value of the voltage from nominal voltage for a time greater than 1 minute.

Long Term Flicker Severity. A value derived from 12 successive measurements of Short Term Flicker Severity over a two-hour period. It is calculated as the cube root of the mean sum of the cubes of 12 individual measurements.

Loss of Mains. A situation in which, due to an incident and/or abnormal situation, a portion of the distribution network, to which the Embedded Generating Plant is connected, separates from the main Distribution System forming an island.

Low Voltage (LV). A voltage level not exceeding 1000 volts.

Maintenance Program. A set of schedules, which are coordinated by the Distribution Utility and the System Operator, specifying planned maintenance for Equipment in the Distribution System or in any User System.

Manufacturer. A person or organization that manufactures Embedded Generating Units and also 'packages' Components manufactured by others to make a Generating Plant which can be Type Tested to meet the requirements of the Philippine Distribution Code.

Major Event. Designates an Event that exceeds reasonable design and/or operational limits of the electric power System. A Major Event includes at least one Major Event Day (MED).

Major Event Day (MED). A day in which the daily SAIDI exceeds a threshold value, T_{MED} . For the purpose of calculating daily system SAIDI, any Interruption that spans multiple calendar days is accrued to the day on which the Interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported.

Major Storm Disaster. A weather condition wherein the design limits of Equipment or Components are exceeded, and which results in extensive mechanical fatigue to Equipment, widespread customer interruption, and unusually long service restoration time.

Manual Load Dropping (MLD). The process of manually and deliberately removing pre-selected Loads from a power system, in response to an abnormal condition, and in order to maintain the integrity of the System.

- Market Operator.** The entity responsible for the operation of the Wholesale Electricity Spot Market (WESM) in accordance with the WESM Rules.
- Material Effect.** A condition that has resulted or expected to result in problems involving any of the following: Power Quality, System Reliability, System Loss, and safety. Such condition may require extensive work, modification, or replacement of Equipment in the Grid, Distribution System, or the System of any User.
- Medium Voltage (MV).** A voltage level exceeding 1 kV up to 34.5 kV.
- Meter.** A device, which measures and records the consumption or production of electricity.
- Metering Data.** The measurement data obtained from metering facilities for purposes of commercial settlements, operational monitoring and planning.
- Metering Equipment.** The apparatus necessary for measuring electrical Active and Reactive Power and Energy, inclusive of a multi-function Meter and the necessary instrument potential, current and phase shifting transformers and all wiring and communication devices provided.
- Metering Point.** A location where the Metering Equipment is installed.
- Metering Service Provider.** A person or entity authorized by the ERC to provide metering services.
- Minimum Load.** The minimum registered load in a given period or particular type of generation.
- Minimum Stable Loading (P_{min}).** The minimum net output in MW that a Generating Unit, generating block or module, can continuously and reliably sustain based on the Generating Unit capability tests.
- Modification.** Any actual or proposed replacement, renovation, or construction in the Distribution System or the User System that may have a Material Effect on the Distribution System or the System of any User.
- Momentary Average Interruption Frequency Index (MAIFI).** Indicates the average frequency of Momentary Interruptions.
- Momentary Interruption.** A single operation of an interrupting device that results in a voltage zero. For example, two operations of Circuit Breaker or recloser (each operation being an open followed by a close) that momentarily interrupt service to one or more customers is defined as two Momentary Interruptions.
- Multiple Outage Contingency.** An Event caused by the failure of two or more Components of the Grid.
- National Electrification Administration (NEA).** The government agency created under Presidential Decree No. 269, whose additional mandate includes preparing Electric Cooperatives in operating and competing under a deregulated electricity market, strengthening their technical capability, and enhancing their financial viability as electric utilities through improved regulatory policies.
- National Power Corporation (NPC).** The government corporation created under Republic Act No. 6395, as amended, whose generation assets, real estate, and other disposable assets, except for the assets of SPUG and for IPP contracts, shall be privatized, and whose transmission assets shall be transferred to the Power Sector Assets and Liabilities Management Corporation (PSALM).
- Net Declared Capacity.** The capacity of a Generating Unit or Generating Plant less the MW consumed by the Generating Unit or Generating Plant as declared by the Generation Company.

Net Metering. A system, appropriate for distributed generation, in which a distribution grid user has a two-way connection to the grid and is only charged or credited, as the case may be, the difference between its import energy and export energy.

Non-Technical Loss. The component of System Loss that is not related to the physical characteristics and functions of the electrical system, and is caused primarily by human action, whether intentional or not. Non-Technical Loss includes the Energy lost due to pilferage, tampering of Meters, and erroneous Meter reading.

Normal State. The Grid operating condition when the system Frequency, Voltage, and transmission line and Equipment loading are within their normal operating limits, the Operating Margin is sufficient, and the Grid configuration is such that any fault current can be interrupted and the faulted equipment isolated from the Grid.

Operating Margin. The available generating capacity in excess of the sum of the system Demand plus losses within a specified period of time.

Operational Thermal Limit Capacity. The maximum capacity of transmission facilities determined and declared by the System Operator and Transmission Network Provider which is submitted to GMC for validation annually.

Outage. The state of a Component when it is not available to perform its intended function due to some Event directly associated with that Component. An Outage may or may not cause an Interruption of service to Customers.

Overall Standards. Refer to the Customer Services where it is not appropriate to give individual guarantees but where Customers have a right to expect the Distribution Utility (or Supplier) to deliver a predetermined reasonable level of performance.

Overvoltage. A Long Duration Voltage Variation where the RMS value of the voltage is greater than or equal to 110% of the nominal voltage.

Partial System Blackout. The condition when a part of the Grid is isolated from the rest of the Grid and all generation in that part of the Grid has Shutdown.

Philippine Distribution Code (PDC). The set of rules, requirements, procedures, and standards governing Distribution Utilities and Users in the operation, maintenance, and development of their Distribution Systems. It also defines and establishes the relationship of the Distribution Systems with the facilities or installations of the parties connected thereto.

Philippine Electrical Code (PEC). The electrical safety code that establishes basic materials quality and electrical work standards for the safe use of electricity for light, heat, power, communications, signaling, and for other purposes.

Philippine Grid Code. The set of rules, requirements, procedures, and standards to ensure the safe, reliable, secured and efficient operation, maintenance, and development of the Grid and its related facilities.

Philippine Energy Plan (PEP). The overall energy program formulated and updated yearly by the DOE and submitted to Congress pursuant to R.A. 7638.

Photovoltaic (PV). A method of generating electrical energy by converting solar radiation into direct current electricity using semiconductors that directly produce electricity when exposed to light.

Photovoltaic Generation System (PVS). A power system which is made up of one or more solar panels, a controller or inverter, and the interconnections and mounting for the other components, which is connected to the system at a single Connection Point.

- Planned Activity Notice.** A notice issued by a User to the Distribution Utility for any planned activity, such as a planned Shutdown or Scheduled Maintenance of its Equipment, at least 3 days prior to the actual Shutdown or maintenance.
- Point of Grounding.** The point on the Distribution System or the User System at which Grounding can be established for safety purposes.
- Point of Isolation.** The point on the Distribution System or the User System at which Isolation can be established for safety purposes.
- Power Development Program (PDP).** The indicative plan for managing Demand through energy-efficient programs and for the upgrading, expansion, rehabilitation, repair, and maintenance of power generation and transmission facilities, formulated and updated yearly by the DOE in coordination with Generation Companies, the Transmission Network Provider, System Operator, and Distribution Utilities.
- Power Factor.** The ratio of Active Power to Apparent Power.
- Power Quality.** The quality of the voltage, including its frequency and resulting current, that is measured in the Grid, Distribution System, or any User System during normal conditions.
- Preliminary Project Planning Data.** The data relating to a proposed User Development at the time the User applies for a Connection Agreement or an Amended Connection Agreement.
- Prescriptive Approach.** The process of evaluating a Distribution Utility's (or Supplier's) Customer Service Program by comparing its actual performance with the targets approved by the ERC.
- Primary Response.** The autonomous response of a Generating Unit to frequency changes typically provided by the action of the speed governors of a synchronous Generating Unit. Primary Response is provided in the first few seconds following a Frequency change and is maintained to a new settling Frequency until it is replaced by Automatic Generation Control.
- Primary Reserve.** Synchronized generating capacity that is allocated to stabilize the system frequency and to cover the loss or failure of a Synchronized Generating Unit or a transmission line or the power import from a single circuit interconnection.
- Rated Capacity.** The continuous load-carrying ability of transmission, distribution or other electrical equipment expressed in either megavolt-amperes (MVA), or megavolt-amperes reactive (MVAR), or megawatts (MW).
- Reactive Energy.** The integral of the Reactive Power with respect to time, measured in VARh, or multiples thereof.
- Reactive Power.** The component of electrical power representing the alternating exchange of stored energy (inductive or capacitive) between sources and loads or between two Systems, measured in VAR, or multiples thereof. For AC circuits or Systems, it is the product of the RMS voltage and the RMS value of the quadrature component of alternating current. In three-phase systems, it is the sum of the Reactive Power of the individual phases.
- Reactive Power Capability Curve.** A diagram which shows the Reactive Power capability limit versus the Real Power within which a Generating Unit is expected to operate under normal conditions.
- Red Alert.** An alert notice issued by the System Operator when the Primary Reserve is zero, a generation deficiency exists, or there is critical loading or imminent overloading of transmission lines or Equipment.

Reliability. The probability that a System or Component will perform a required task or mission for a specified time in a specified environment. It is the ability of a power system to continuously provide service to its Customers.

Requesting Safety Coordinator. The Safety Coordinator assigned by the Distribution Utility (or the User) when it requests that Safety Precautions be established in the User System (or the Distribution System).

Safety Coordinator. A person designated/authorized by the Distribution Utility (or the User) to be responsible for the coordination of Safety Precautions at the Connection Point when work or testing is to be carried out on a System which requires the provision of Safety Precautions for MV or HV Equipment.

Safety Log. A chronological record of messages relating to safety coordination sent and received by each Safety Coordinator.

Safety Precautions. Refers to the Isolation and Grounding of MV or HV Equipment when work or testing is to be done on the Distribution System or User System.

Safety Rules. The rules that seek to safeguard personnel working on the Distribution System (or User System) from the hazards arising from the Equipment or the Distribution System (or User System).

Safety Tag. A label conveying a warning against possible interference or intervention as defined in the safety clearance and tagging procedures.

Scheduled Generating Plant. A Generating Plant whose Generating Units are subject to Central Dispatch by the System Operator.

Scheduled Generating Unit. A Generating Unit within a Scheduled Generating Plant.

Scheduled Maintenance. The Outage of a Component or Equipment due to maintenance, which is coordinated by the Distribution Utility or User, as the case may be.

Secondary Response. The centralized automatic response through Automatic Generation Control of a qualified generating unit to raise or lower signal automatically through SCADA of the System Operator, with the aim of maintaining the Frequency at a pre-established value and/or returning the Frequency to nominal values.

Secondary Reserve. Synchronized generating capacity that is allocated to restore the system frequency from the quasi-steady state value as established by the Primary Responses of Generating Units to the nominal Frequency of 60 Hz.

Security. The continuous operation of a power system in the Normal State, ensuring safe and adequate supply of power to End-Users, even when some parts or Components of the System are on Outage.

Short Duration Voltage Variation. A variation of the RMS value of the voltage from its nominal value for a time greater than one-half cycle of the power frequency but not exceeding one minute.

Short Term Flicker Severity. A measure of the visual severity of Flicker derived from a time-series output of a flicker meter over a 10-minute period.

Shutdown. The condition of an Equipment when it is de-energized or disconnected from the System.

Significant Incident. An Event on the Distribution System or the System of any User that has a serious or widespread effect on the Distribution System and/or the System of the User.

- Significant Incident Notice.** A notice issued by the Distribution Utility or any User if a Significant Incident has transpired on the Distribution System or the System of the User, as the case may be.
- Site.** Refers to a substation or switchyard in the Grid, Distribution System or the User System where the Connection Point is situated.
- Small Power Utilities Group (SPUG).** The functional unit of NPC created to pursue the missionary electrification function.
- Spot Market.** Has the same meaning as the Wholesale Electricity Spot Market.
- Stability.** The ability of the dynamic Components of the power system to return to a normal or stable operating point after being subjected to some form of change or disturbance.
- Standard Planning Data.** The general data required by the Distribution Utility as part of the application for a Connection Agreement or Amended Connection Agreement.
- Start-Up.** The process of bringing a Generating Unit from Shutdown to synchronous speed.
- Supplier.** Any person or entity authorized by the ERC to sell, broker, market, or aggregate electricity to the End-Users.
- Supply of Electricity.** The sale of electricity by a party other than a Generation Company or a Distribution Utility in the Franchise Area of a Distribution Utility using the wires of the Distribution Utility concerned.
- Sustained Interruption.** Any Interruption not classified as a part of a momentary Event. That is, any Interruption that lasts more than 5 minutes.
- Synchronized.** The state when connected Generating Units and/or interconnected AC Systems operate at the same Frequency and where the phase angle displacements between their voltages vary about a stable operating point.
- System.** Refers to the Grid or Distribution System or any User System. Also, a group of Components connected or associated in a fixed configuration to perform a specified function.
- System Average Interruption Duration Index (SAIDI).** Indicates the total duration of Interruption for the average Customer during a predefined period of time. It is commonly measured in customer minutes or customer hours of Interruption.
- System Average Interruption Frequency Index (SAIFI).** Indicates how often the average Customer experiences a Sustained Interruption over a predefined period of time.
- System Loss.** In a Distribution System, it is the difference between the electric energy delivered to the Distribution System and the Energy delivered to the End-Users and other entities connected to the System.
- System Operator.** The party responsible for generation dispatch, the provision of Ancillary Services, and operation and control to ensure safety, Power Quality, Stability, Reliability, and the Security of the Grid.
- System Test.** The set of tests which involve simulating conditions or the controlled application of unusual or extreme conditions that may have an impact on the Distribution System or the User System.
- System Test Coordinator.** A person who is appointed as the chairman of the System Test Group.
- System Test Group.** A group established for the purpose of coordinating the System Test to be carried out on the Distribution System or the User System.

- System Test Procedure.** A procedure that specifies the switching sequence and proposed timing of the switching sequence, including other activities deemed necessary and appropriate by the System Test Group in carrying out the System Test.
- System Test Proponent.** Refers to the Distribution Utility or the User who plans to undertake a System Test and who submits a System Test Request to the Distribution Utility (if it is not the System Test Proponent).
- System Test Program.** A program prepared by the System Test Group, which contains the plan for carrying out the System Test, the System Test Procedure, including the manner in which the System Test is to be monitored, the allocation of cost among the affected parties, and other matters that the System Test Group had deemed appropriate and necessary.
- System Test Report.** A report prepared by the Test Proponent at the conclusion of a System Test for submission to the Distribution Utility, affected Users, and the members of the System Test Group.
- System Test Request.** A notice submitted by the System Test Proponent to the Distribution Utility indicating the purpose, nature, and procedures for carrying out the proposed System Test.
- Technical Loss.** The component of System Loss that is inherent in the physical delivery of electric energy. It includes conductor loss, transformer core loss, and technical error in Meters.
- Test and Commissioning.** Putting into service a System or Equipment that has passed all required tests to show that the System or Equipment was erected and connected in the proper manner and can be expected to work satisfactorily.
- Total Demand Distortion (TDD).** The total root-sum-square harmonic current distortion, in percent of the maximum demand load current (15 or 30 min. demand).
- Total Harmonic Distortion (THD).** The ratio of the root-mean-square (RMS) value of the sum of the squared individual harmonic amplitudes to the RMS value of the fundamental frequency of a complex waveform.
- Total System.** Refers to the Grid and all User Systems connected to it.
- Total System Blackout.** The condition when all generation in the Grid has ceased, the entire System has Shutdown, and the System Operator must implement a Black Start to restore the Grid to its Normal State.
- Transformer.** An electrical device or Equipment that converts Voltage and Current from one level to another.
- Transactions Survey.** A statistically valid sample survey of Customers who have had recent interaction, excluding regular payment of bills, with the Distribution Utility (or Supplier).
- Transient Voltages.** High-frequency Overvoltages caused by lightning, switching of capacitor banks or cables, current chopping, arcing ground faults, ferroresonance, and other related phenomena.
- Transmission Network Provider.** The party that is responsible for maintaining adequate Grid Capacity in accordance with the provisions of the Philippine Grid Code.
- Type Tested.** A Generating Plant design which has been tested by the Manufacturer, component Manufacturer or supplier, or a third party, to ensure that the design meets the requirements of the Philippine Distribution Code, and for which the

Manufacturer has declared that all products supplied will be constructed to the same standards, and with the same protection settings as the tested product.

Underfrequency Relay (UFR). An electrical relay that operates when the system frequency decreases to a preset value.

Undervoltage. A Long Duration Voltage Variation where the RMS value of the voltage is less than or equal to 90% of the nominal voltage.

User. A person or entity that uses the Distribution System and related distribution facilities. User also refers to a person or entity to which the Philippine Distribution Code applies.

User Development. The System or Equipment to be connected to the Distribution System or to be modified, including the relevant proposed new connections and/or modifications within the User System that requires a Connection Agreement or an Amended Connection Agreement.

User System. Refers to a System owned or operated by a User of the Distribution System.

Variable Renewable Energy (VRE) Generation Company. Refers to an Embedded Generation Company that is authorized by the ERC to operate a Variable Renewable Energy Generating Facility.

Variable Renewable Energy (VRE) Generating Facility. A facility, consisting of one or more Generating Units, where electric Energy is produced from a source that is renewable, cannot be stored by the facility owner or operator and has inherent intermittency that is beyond the control of the facility owner or operator. For the avoidance of doubt, it includes Wind Farms, Photovoltaic Generation Systems and run-of-river hydraulic plants, provided that the storage capability of the dam does not exceed 2 hours at average inflow.

Variable Renewable Energy (VRE) Installed Capacity. The sum of rated generating capacity of each Wind Turbine Generating Unit in a Wind Farm or the sum of rated generating capacity of each solar panel in a Photovoltaic Generation System, expressed in MW (or kW).

Voltage. The electromotive force or electric potential difference between two points which causes the flow of electric current in an electric circuit.

Voltage Control. The strategy used by the Distribution Utility or User to maintain the Voltage of the Distribution System or the User System within the limits prescribed by the Philippine Distribution Code.

Voltage Sag. A Short Duration Voltage Variation where the RMS value of the voltage decreases to between 10% and 90% of the nominal value. Voltage Sag is also known as Voltage Dip.

Voltage Swell. A Short Duration Voltage Variation where the RMS value of the voltage increases to between 110% and 180% of the nominal value.

Voltage Transformer. A device that scales down primary voltage supplied to a Meter while providing electrical Isolation.

Voltage Unbalance. The maximum deviation from the average of the three phase voltages divided by the average of the three phase voltages, expressed in percent.

Voltage Variation. The deviation of the root-mean-square (RMS) value of the voltage from its nominal value, expressed in percent.

Voluntary Demand Management. The demand disconnection initiated by the Users, Customer Demand Management and Voluntary Load Curtailment.

Voluntary Load Curtailment (VLC). The agreed self-reduction of Demand by identified industrial and commercial End-Users to assist in Frequency Control when generation deficiency exists. This is also known as Interruptible Load Program (ILP).

Wheeling Charge. Refers to the tariff paid for the conveyance of electric power and Energy through the Grid or a Distribution System.

Wholesale Electricity Spot Market (WESM). The electricity market established by the DOE pursuant to Section 30 of the Act.

Wind Farm. A collection of Wind Turbine Generating Units that are connected to the grid at a single Connection Point.

Wind Turbine Generating Unit: A Generating Unit that uses wind as primary resource.

1.8 ABBREVIATIONS

AC	Alternating Current
AGC	Automatic Generation Control
ALD	Automatic Load Dropping
CAIDI	Customer Average Interruption Duration Index
CCPD	Coupling Capacitor Potential Devices
DDP	Distribution Development Plan
DMC	Distribution Management Committee
DOE	Department of Energy
EBIT	Earnings Before Interest and Taxes
EPC	Engineering, Procurement and Construction
ERC	Energy Regulatory Commission
FGM	Free Governor Mode
GW	Gigawatt
GWh	Gigawatt-hour
HV	High Voltage
IEC	International Electrotechnical Commission
IRR	Implementing Rules and Regulations
kA	Kiloampere
kVARh	Kilo-var-hour
kW	Kilowatt
kWh	Kilowatt-hour
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MED	Major Event Day
MLD	Manual Load Dropping
MSP	Metering Service Provider
MV	Medium Voltage
MVA	Megavolt-ampere
MVAR	Megavolt-amperes reactive
MVARh	Megavar-hour

MW	Megawatt
MWh	Megawatt-hour
NEA	National Electrification Administration
PDP	Power Development Program
PEC	Philippine Electrical Code
PEP	Philippine Energy Plan
PV	Photovoltaic
PVS	Photovoltaic Generation System
RMS	Root-Mean-Square
ROA	Return on Assets
RoCoF	Rate of Change of Frequency
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SPUG	Small Power Utility Group
TDD	Total Demand Distortion
THD	Total Harmonic Distortion
TNP	Transmission Network Provider
UFLS	Under-Frequency Load Shedding
UFR	Underfrequency Relay
UVLS	Under-Voltage Load Shedding
V	Volts
VA	Volt Ampere
VAR	Volt Ampere Reactive
VRE	Variable Renewable Energy
W	Watt
WESM	Wholesale Electricity Spot Market
Wh	Watt-hour
X/R	Reactance/Resistance

CHAPTER 2

DISTRIBUTION MANAGEMENT

2.1 PURPOSE

- (a) To facilitate the monitoring of compliance with the Philippine Distribution Code at the planning, operations and maintenance level;
- (a) To ensure that all Users of the Distribution System are represented in reviewing and making recommendations pertaining to connection, operation, maintenance, and development of the Distribution System; and
- (b) To specify the processes for the enforcement, interpretation and review of the Philippine Distribution Code.

2.2 DISTRIBUTION MANAGEMENT COMMITTEE

2.2.1 Functions of the Distribution Management Committee

There shall be established a Distribution Management Committee (DMC), which shall carry out the following functions:

- (a) Monitor the implementation of the Philippine Distribution Code;
- (b) Monitor, evaluate, and make recommendations on Distribution operations;
- (c) Review and recommend standards, procedures, and requirements for distribution system connection, operation, maintenance, and development;
- (d) Manage queries on the application and/or interpretation of the provisions of the Philippine Distribution Code, and make appropriate recommendations to the ERC;
- (e) Initiate the Philippine Distribution Code enforcement process and make recommendations to the ERC;
- (f) Initiate and coordinate revisions of the Philippine Distribution Code and make recommendations to the ERC; and
- (g) Prepare regular and special reports for submission to the ERC, or as required by the appropriate government agency, or when requested by a User.

2.2.2 Membership of the DMC

2.2.2.1 The DMC shall be composed of the following 15 regular members appointed by the ERC:

- (a) Three members nominated by private and local government Distribution Utilities excluding the largest Distribution Utility, one each from Luzon, Visayas, and Mindanao;
- (b) Three members nominated by the Electric Cooperatives excluding the largest Distribution Utility, one each from Luzon, Visayas, and Mindanao;
- (c) One member nominated by the largest Distribution Utility;
- (d) One member nominated by Embedded Generation Companies;

- (e) One member nominated by industrial Customers;
- (f) One member nominated by commercial Customers;
- (g) One member nominated by residential consumer groups;
- (h) One member nominated by the Transmission Network Provider;
- (i) One member nominated by the System Operator;
- (j) One member nominated by the Market Operator; and
- (k) One member nominated by a government-accredited professional organization of electrical engineers.

2.2.2.2 In addition to the regular members, there shall be three representatives, one each from ERC, DOE, and NEA to provide guidance on government policy and regulatory frameworks and directions. The government representatives shall not participate in any DMC decision-making and in the formulation of recommendations to the ERC.

2.2.2.3 The ERC shall issue the guidelines and procedures for the nomination and selection of the DMC members.

2.2.2.4 The Chairman of the DMC shall be selected by the ERC from a list of three regular members nominated by the DMC.

2.2.2.5 The members of the DMC shall be a registered electrical engineer and shall have sufficient technical background and experience of at least 10 years in the Electric Power Industry to fully understand and evaluate the technical aspects of distribution system operation, planning, and development.

2.2.3 Terms of Office of the DMC Members

2.2.3.1 A regular member of the DMC shall have a term of 3 years, and may be reappointed by the ERC. However, in view of numerous activities to be accomplished after the approval of the Philippine Distribution Code's latest edition, the DMC will require a period of 18 months to finish the same. Consequently, existing members whose term will expire within the 18-month period shall continue to serve on holdover capacity until the end of the said 18-month period, provided that at least two-thirds of the total number of current members shall remain. In the event that the remaining membership falls below two-thirds, the period of being on hold-over capacity shall go beyond the 18-month period until the successor of the concerned member shall have been appointed.

2.2.3.2 For the purpose of continuity and stability in the DMC, at least two-thirds of the total number of the members shall remain every year. Notwithstanding the limitations set forth in 2.2.3.1, the term of the successor of the member who served on hold-over capacity under 2.2.3.1 shall be the remaining unexpired period of the three-year term of a regular member.

2.2.3.3 Appointment to any future vacancy shall be only for the remaining term of the predecessor.

2.2.3.4 Any member of the DMC may be removed from the Committee, after due notice, by the ERC upon its own initiative or upon the recommendation of the DMC for neglect of duty, incompetence,

malpractice, or for unprofessional, unethical, or dishonorable conduct, or such other ground as may be determined by the ERC.

2.2.4 DMC Support Staff and Operating Cost

2.2.4.1 The DMC operations, including its subcommittees and permanent support staff, shall be funded by a charge shared among all Distribution Utilities as a direct proportion of their annual Energy sales.

2.2.4.2 The DMC shall prepare and submit its operating budget requirements for the following year by September of the current year for approval of ERC in accordance with ERC's Rules and Regulations. The budget shall include all operational cost of DMC permanent staff, and the honoraria of DMC members and subcommittee members, if any. The ERC shall issue a resolution pertaining to the approval of the DMC budget. A yearly report on budget utilization shall be submitted to the ERC.

2.2.4.3 The salaries of all DMC members and all subcommittee members shall be the responsibility of their respective employers or sponsoring organizations.

2.2.5 DMC Rules and Procedures

2.2.5.1 The DMC shall establish and publish its own rules and procedures relating to the conduct of its functions. These include but are not limited to the following:

- (a) Administration and operation of the Committee;
- (b) Establishment and operation of DMC subcommittees;
- (c) Evaluation of Distribution System operations reports;
- (d) Managing queries on the application and/or interpretation of any provision of the Philippine Distribution Code;
- (e) Monitoring of Philippine Distribution Code enforcement;
- (f) Amendments to and revision of the Philippine Distribution Code provisions;
- (g) Review of Distribution Development Plans; and
- (h) Review of major distribution system reinforcement and expansion projects.

2.2.5.2 The rules and procedures of the DMC shall be approved by the ERC.

2.2.5.3 The DMC is expected to decide on issues based on consensus rather than by simple majority voting.

2.3 DISTRIBUTION MANAGEMENT SUBCOMMITTEES

2.3.1 Distribution Planning Subcommittee

2.3.1.1 The DMC shall establish a permanent Distribution Planning Subcommittee with the following functions:

- (a) Reviewing and revising the Distribution System planning procedures and standards;
- (b) Evaluating and making recommendations on the Distribution Development Plan; and

(c) Evaluating and recommending actions on the proposed major Distribution System reinforcement and expansion projects.

2.3.1.2 The chairman and members of the Distribution Planning Subcommittee shall be appointed by the DMC.

2.3.1.3 The members of the Distribution Planning Subcommittee shall have sufficient technical background and experience in distribution planning.

2.3.2 Distribution Operations Subcommittee

2.3.2.1 The DMC shall establish a permanent Distribution Operations Subcommittee with the following functions:

(a) Reviewing and revising the distribution system operation technical standards, such as:

- (1) Equipment standards;
- (2) Standard operating procedures;
- (3) Performance standards; and
- (4) Metering standards.

(b) Reviewing and revising the Distribution System operating procedures, such as:

- (1) Joint purchases of common Equipment;
- (2) Sharing of parts inventories;
- (3) Mutual assistance; and
- (4) Emergency response.

(c) Evaluating and making recommendations on Distribution System operation reports;

(d) Evaluating and making recommendations on Significant Incidents; and

(e) Monitoring the implementation of the Philippines Small Grid Guidelines.

2.3.2.2 The chairman and members of the Distribution Operations Subcommittee shall be appointed by the DMC.

2.3.2.3 The members of the Distribution Operations Subcommittee shall have sufficient technical background and experience in distribution system operations.

2.3.3 Distribution Reliability and Protection Subcommittee

2.3.3.1 The DMC shall establish a permanent Distribution Protection and Reliability Subcommittee with the following functions:

(a) Reviewing and revising Distribution System reliability and protection procedures and standards;

(b) Evaluating and making recommendations on distribution reliability reports;

(c) Evaluating and making recommendations on significant distribution system Events or incidents caused by the failure of protection;

(d) Reviewing and recommending reliability performance standards; and

(e) Managing reliability data.

2.3.3.2 The chairman and members of the Distribution Protection and Reliability Subcommittee shall be appointed by the DMC.

2.3.3.3 The members of the Distribution Protection and Reliability Subcommittee shall have sufficient technical background and experience in Distribution System reliability and protection.

2.3.4 Compliance Subcommittee

2.3.4.1 The DMC shall establish a permanent Compliance Subcommittee with the following functions:

- (a) Implementing rules and regulations pertaining to the compliance of Distribution Utilities with the Philippine Distribution Code;
- (b) Evaluating and making recommendations on the Distribution Utility's compliance monitoring report with the Philippine Distribution Code;
- (c) Conducting actual assessment of Distribution Utility's compliance with the Philippine Distribution Code;
- (d) Implementing rules and regulations pertaining to the compliance of small grid users with the Philippine Small Grid Guidelines; and
- (e) Monitoring and conducting actual compliance of small grid users with the Philippine Small Grid Guidelines.

2.3.4.2 The chairman and members of the Compliance Subcommittee shall be appointed by the DMC.

2.3.4.3 The members of the Compliance Subcommittee shall have sufficient technical background and experience in distribution operations and planning, including regulation of the power industry.

2.3.5 Rules Review Subcommittee

2.3.5.1 The DMC shall establish a permanent Rules Review Subcommittee with the following functions:

- (a) Initiating proposals for appropriate amendments to and/or revisions of the Philippine Distribution Code;
- (b) Evaluating and making recommendations on the proposed amendments to and/or revisions of the Philippine Distribution Code; and
- (c) Evaluating and making recommendations on any rules and regulations to be issued by the ERC and/or other agencies.

2.3.5.2 The chairman and members of the Rules Review Subcommittee shall be appointed by the DMC.

2.3.5.3 The members of the Rules Review Subcommittee shall have sufficient technical background and experience in distribution operations and planning, including regulation of the power industry.

2.3.6 Other Distribution Subcommittees

The DMC may establish other ad hoc subcommittees as necessary.

2.4 APPLICATION AND INTERPRETATION OF THE PHILIPPINE DISTRIBUTION CODE PROVISIONS

Queries on the interpretation and/or application of any of the provisions of the Philippine Distribution Code will arise from time to time. This Article applies to the Distribution Utility and all Users of the Distribution System with respect to the provisions of the Philippine Distribution Code.

It is expected that a query is submitted by a party in good faith, with the aim of clarifying a particular issue, and not to unnecessarily delay related processes or procedures.

Queries involving the interpretation and/or application of any of the provisions of the Philippine Distribution Code may be referred to the DMC for clarification or comment, in accordance with the following procedure:

- (a) A party may submit a query in writing to the DMC copy furnished the other party or parties, if any, and clearly state therein the factual antecedents and the provision(s) of the Philippine Distribution Code in issue.
- (b) Upon verification by the DMC that the query is within the scope of this Article, it may refer the matter to the appropriate subcommittee, or form an ad hoc subcommittee composed of three or five members who have the technical background to understand the technical merits and implications of the inquiry.
- (c) The subcommittee shall hold meetings within a period to be prescribed by the DMC, to discuss the merits of the query and to receive supporting documents, as may be necessary.
- (d) The proceedings undertaken, reply to the query and any recommendations of the subcommittee shall be documented and presented to the DMC.
- (e) The DMC shall provide a formal reply to the query including any recommendations, copy furnished the ERC.
- (f) In cases where the ERC refers a matter to the DMC within the scope of this Article for comment or clarification, the procedures in paragraphs (b) to (e) shall be observed.

2.5 PHILIPPINE DISTRIBUTION CODE ENFORCEMENT AND REVISION PROCESS

2.5.1 Enforcement Process

2.5.1.1 Any party that has evidence that any other party has violated or is violating any provision of the Philippine Distribution Code may file a complaint to the DMC who shall initiate an enforcement process. The DMC may initiate the enforcement process even if no complaint has been filed but it has information on possible Philippine Distribution Code violations. The ERC may also direct the DMC to begin the enforcement process.

2.5.1.2 The steps of the enforcement process are as follows:

- (a) The DMC shall send a written notice to the offending party with the specifics of the alleged violation and the recommended course of action needed to correct the alleged violation;

- (b) The offending party shall respond in writing, within 30 days from receipt of the notice from the DMC, its reaction to the alleged violation and to state whether or not it shall comply with the course of action recommended by the DMC;
- (c) If the DMC is satisfied with the response, it shall make a report, including the recommended course of action, to the ERC who shall render the final decision on the matter; and
- (d) If the DMC is not satisfied with the response, it shall document the charges against the offending party and submit a report, including the recommended course of action, fines, and penalties to the ERC.

2.5.2 Fines and Penalties

To effectively enforce the Philippine Distribution Code, the ERC shall impose the fines or penalties prescribed by the Act for any non-compliance with or breach of any provision of the Philippine Distribution Code.

2.5.3 Unforeseen Circumstances

- 2.5.3.1 If a situation arises which the provisions of the Philippine Distribution Code have not foreseen, the Distribution Utility shall, to the extent reasonably practicable, consult promptly all affected Users and Suppliers in an effort to reach agreement as to what should be done.
- 2.5.3.2 If an emergency situation arises which the provisions of the Philippine Distribution Code have not foreseen, the Distribution Utility shall take whatever step it deems necessary to its best judgment. A report of the actions taken, results and assessment shall be furnished to the DMC, affected Users, and Suppliers for documentation and record purposes.
- 2.5.3.3 If an agreement is reached, the Distribution Utility shall promptly refer the matter, including the agreement, to the DMC for review and to make the appropriate recommendations to the ERC.
- 2.5.3.4 If an agreement is not reached, the Distribution Utility shall decide what is to be done if the emergency situation has resulted in a Significant Incident. In such case, all Users shall comply with all instructions issued by the Distribution Utility to the extent that such instructions are consistent with the technical characteristics of the User System as registered under the Philippine Distribution Code. The Distribution Utility shall be answerable to the DMC and the ERC for unjustified unilateral actions or measures it has taken against any User.

2.5.4 Philippine Distribution Code Amendment and Revision Process

- 2.5.4.1 Any party who has a proposal to amend any provision of the Philippine Distribution Code shall submit the proposal in writing, including the supporting arguments and data, to the DMC for evaluation.
- 2.5.4.2 If the DMC agrees with the proposed amendment, it shall make the appropriate recommendations to the ERC.
- 2.5.4.3 If the DMC disagrees with the proposed amendment, it shall submit a report stating the justifications for its position to the ERC.

2.5.4.4 The DMC, through its Rules Review Subcommittee, starting 2010 and every 3 years thereafter, shall initiate revision of the Philippine Distribution Code.

2.5.4.5 The ERC shall render the final decision on any matter pertaining to Philippine Distribution Code amendments and revision.

2.6 DISTRIBUTION MANAGEMENT REPORTS

2.6.1 Quarterly and Annual Reports

2.6.1.1 The DMC shall submit to the ERC four quarterly reports before the end of the month immediately following the quarter.

2.6.1.2 The DMC shall submit to the ERC an annual report for the previous year by the end of March of the current year.

2.6.2 Significant Incident Reports

2.6.2.1 The following Events are considered Significant Incidents:

- (a) Outage of at least one substation, whose primary voltage is 69 kV and above and owned by the Distribution Utility, for at least 1 hour;
- (b) Service Interruption for at least 15 minutes affecting at least 25% of previous month's customers; and
- (c) Service Interruptions for at least 15 minutes affecting at least 25% of previous year's peak demand.

2.6.2.2 Within 2 weeks following a Significant Incident in the Distribution System or the User System, the Distribution Utility shall submit to the DMC and the ERC a report detailing the sequence of events and other relevant information pertaining to the incident. The report shall describe the cause of the Significant Incident and the amount and duration of the resulting power Interruptions.

2.6.2.3 Within 1 month following the receipt of the Distribution Utility's report on the Significant Incident, the DMC shall validate the report and make recommendations to the ERC. In cases where any User has violated any provision of the Philippine Distribution Code, the DMC may recommend to the ERC sanctions as part of the Significant Incident report.

2.6.3 Special Reports

The DMC shall prepare special reports as ordered by the ERC or any appropriate government agency, or at the request of any User, or as it deems necessary. Special reports prepared at the request of any User shall be at the expense of the User.

CHAPTER 3

PERFORMANCE STANDARDS FOR DISTRIBUTION AND SUPPLY

3.1 PURPOSE

- (a) To ensure the quality of electric power in the Distribution System;
- (b) To ensure that the Distribution System will be operated in a safe and efficient manner and with a high degree of reliability;
- (c) To specify Customer Services for the protection of the End-Users in both the captive and contestable markets; and
- (d) To specify safety standards for the protection of personnel in the work environment.

3.2 POWER QUALITY STANDARDS FOR DISTRIBUTION UTILITIES

3.2.1 Power Quality Problems

- 3.2.1.1 For the purpose of this Article, Power Quality shall be defined as the quality of the voltage, including its Frequency and the resulting current, that are measured in the Distribution System during normal conditions.
- 3.2.1.2 A Power Quality problem exists when at least one of the following conditions is present and significantly affects the normal operation of the System:
 - (a) The system Frequency has deviated from the nominal value of 60 Hz;
 - (b) Voltage magnitudes are outside their allowable range of variation;
 - (c) Harmonic frequencies are present in the System;
 - (d) There is imbalance in the magnitude of the phase Voltages;
 - (e) The phase displacement between the Voltages is not equal to 120 degrees;
 - (f) Voltage fluctuations cause Flicker that is outside the allowable Flicker Severity limits; or
 - (g) High-frequency Overvoltages are present in the Distribution System.

3.2.2 Frequency Variations

- 3.2.2.1 The nominal fundamental Frequency shall be 60 Hz.
- 3.2.2.2 The Distribution Utility shall design and operate its System to assist the System Operator in maintaining the fundamental Frequency within the limits of 59.7 Hz and 60.3 Hz during normal conditions.

3.2.3 Voltage Variations

- 3.2.3.1 For the purpose of this Section, Voltage Variation shall be defined as the deviation of the RMS value of the voltage from its nominal value, expressed in percent. Voltage Variation will either be of short duration or long duration.

3.2.3.2 A Short Duration Voltage Variation shall be defined as a variation of the RMS value of the voltage from nominal Voltage for a time greater than one-half cycle of the power Frequency but not exceeding 1 minute. A Short Duration Voltage Variation is a Voltage Swell if the RMS value of the Voltage increases to between 110% and 180% of the nominal value. A Short Duration Voltage Variation is a Voltage Sag (or Voltage Dip) if the RMS value of the Voltage decreases to between 10% and 90% of the nominal value.

3.2.3.3 A Long Duration Voltage Variation shall be defined as a variation of the RMS value of the Voltage from nominal Voltage for a time greater than 1 minute. A Long Duration Voltage Variation is an Undervoltage if the RMS value of the Voltage is less than or equal to 90% of the nominal Voltage. A Long Duration Voltage Variation is an Overvoltage if the RMS value of the Voltage is greater than or equal to 110% of the nominal value.

3.2.3.4 The Distribution Utility shall ensure that no Undervoltage or Overvoltage is present at the Connection Point of any User during normal operating conditions. The ERC may require the Distribution Utility to comply with a more stringent Voltage Variation limits, which shall be determined from technical and economic studies.

3.2.3.5 The Distribution Utility shall ensure that the Distribution System has sufficient capacity so that Voltage Sags when starting large induction motors will not adversely affect any user facilities or equipment.

3.2.4 Harmonics

3.2.4.1 For the purpose of this Section, Harmonics shall be defined as sinusoidal Voltages and currents having Frequencies that are integral multiples of the fundamental Frequency.

3.2.4.2 The Total Harmonic Distortion (THD) shall be defined as the ratio of the RMS value of the sum of the squared individual harmonic amplitudes to the RMS value of the fundamental Frequency of a complex waveform.

3.2.4.3 The Total Demand Distortion (TDD) shall be defined as the total root-sum-square harmonic current distortion in percent of the maximum demand load current (15-minute or 30-minute demand).

3.2.4.4 At any User System, the THD of the voltage shall not exceed 5% during normal operating conditions.

3.2.4.5 At any User System, the TDD of the current shall not exceed 5% during normal operating conditions.

3.2.5 Voltage Unbalance

3.2.5.1 For the purpose of this Section, Voltage Unbalance shall be defined as the maximum deviation from the average of the three-phase Voltages divided by the average of the three-phase Voltages, expressed in percent.

3.2.5.2 The maximum Voltage Unbalance at the Connection Point of any User, excluding the Voltage Unbalance passed on from the Grid, shall not exceed 2.5% during normal operating conditions.

3.2.6 Flicker Severity

- 3.2.6.1 For the purpose of this Section, Flicker shall be defined as the impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time.
- 3.2.6.2 In the assessment of the disturbance caused by a Flicker source with a short duty cycle, the Short Term Flicker Severity shall be computed over a 10-minute period.
- 3.2.6.3 In the assessment of the disturbance caused by a Flicker sources with a long and variable duty cycle, the Long Term Flicker Severity shall be derived from the Short Term Flicker Severity levels.
- 3.2.6.4 The Flicker Severity at the Connection Point of any User shall not exceed 1.0 unit for short term and 0.8 units for long term.

3.2.7 Transient Voltage Variations

- 3.2.7.1 For the purpose of this Section, Transient Voltages shall be defined as the high-frequency Overvoltages that are generally shorter in duration compared to the Short Duration Voltage Variations.
- 3.2.7.2 Infrequent short-duration peaks may be permitted to exceed the levels specified in Section 3.2.4 for TDD and THD provided that such increases do not compromise the service to other End-Users or cause damage to any Equipment in the Distribution System.

3.3 RELIABILITY STANDARDS FOR DISTRIBUTION UTILITIES

3.3.1 Criteria for Establishing Distribution Reliability Standards

- 3.3.1.1 The ERC shall impose a uniform system of recording and reporting of Distribution System reliability performance.
- 3.3.1.2 The same reliability indices shall be imposed on all Distribution Utilities. However, the numerical levels of performance (or targets) shall be unique to each Distribution System and shall be based initially on its historical performance.
- 3.3.1.3 The Distribution Utilities shall be grouped into different categories, which shall be based on load density, sales mix, cost of service, delivery voltage, and other technical considerations that the ERC may deem appropriate.
- 3.3.1.4 The Distribution System shall be evaluated annually to compare its actual performance with the targets.

3.3.2 Distribution Reliability Indices

- 3.3.2.1 The following distribution reliability indices shall be imposed on all Distribution Utilities:
- (a) System Average Interruption Frequency Index (SAIFI);
 - (b) System Average Interruption Duration Index (SAIDI);
 - (c) Customer Average Interruption Duration Index (CAIDI); and
 - (d) Momentary Average Interruption Frequency Index (MAIFI).

3.3.2.2 The System Average Interruption Frequency Index indicates how often the average Customer experiences a Sustained Interruption over a predefined period of time.

3.3.2.3 The System Average Interruption Duration Index indicates the total duration of Interruption for the average Customer during a predefined period of time. It is commonly measured in Customer minutes or Customer hours of Interruption.

3.3.2.4 The Customer Average Interruption Duration Index represents the average time required to restore service.

3.3.2.5 The Momentary Average Interruption Frequency Index indicates the average frequency of Momentary Interruptions.

3.3.3 Inclusions and Exclusions of Interruption Events

3.3.3.1 A power interruption shall include any Outage in the primary distribution system, extending from the distribution substation to the distribution Transformers, which may be due to the tripping action of protective devices during faults or the failure of primary distribution lines and/or Transformers, and which results in the loss of service to one or more Customers or Users.

3.3.3.2 The following Events shall be excluded in the calculation of the reliability indices:

- (a) Outages that occur on the secondary lines of the Distribution System;
- (b) Outages due to generation, transmission line, or transmission substation failure;
- (c) Planned Outages where the Customers or Users have been notified at least 3 days prior to the loss of power;
- (d) Supply Interruptions made at the request of a customer or authorized customer representative;
- (e) Outages that are initiated by the System Operator/Market Operator during the occurrence of Significant Incidents or the failure of their facilities;
- (f) Outages caused by Adverse Weather or Major Storm Disasters which result in the declaration by the government of a state of calamity in the Franchise Area of the Distribution Utility; and
- (g) Outages due to other events, including Major Events, that the ERC shall approve after due notice and hearing.

3.3.4 Submission of Distribution Reliability Reports and Performance Targets

3.3.4.1 The Distribution Utility shall submit every 3 months the monthly interruption reports for its Distribution System using the standard format prescribed by the ERC.

3.3.4.2 The ERC shall set the performance targets for each Distribution System after due notice and hearing.

3.4 SYSTEM EFFICIENCY STANDARDS FOR DISTRIBUTION UTILITIES

3.4.1 System Loss Classifications

- 3.4.1.1 System Loss shall be classified into two categories: Technical Loss and Non-Technical Loss.
- 3.4.1.2 The Technical Loss shall be the aggregate of conductor loss, the core loss in Transformers, and any loss due to technical metering error.
- 3.4.1.3 The Non-Technical Loss shall be the aggregate of the Energy lost due to pilferage, Meter reading errors, Meter tampering, and any loss that is not related to the physical characteristics and functions of the electric system.

3.4.2 System Loss Cap

- 3.4.2.1 The Distribution Utility shall identify and report separately to the ERC the Technical and Non-Technical Losses in its Distribution System.
- 3.4.2.2 The ERC shall, after due notice and hearing, prescribe a cap on the System Loss that the Distribution Utility can pass on to its End-Users.

3.4.3 Distribution Utility Use

- 3.4.3.1 The Distribution Utility Use shall include the Energy that is required for the proper operation of the Distribution System.
- 3.4.3.2 The Distribution Utility shall submit to ERC an application for the approval of its Distribution Utility Use. The allowance for Distribution Utility Use shall be approved by the ERC, after due notice and hearing, based on connected essential Load.
- 3.4.3.3 Actual Distribution Utility Use shall be treated as part of the Distribution Utility's operations and maintenance expenses, and upon review and approval by ERC, incorporated in its distribution, metering and supply charges.

3.4.4 Power Factor at the Connection Point

- 3.4.4.1 All Users of the Distribution System shall maintain a Power Factor of not less than 85% lagging at the Connection Point.
- 3.4.4.2 The Distribution Utility may establish penalties for User Power Factors that are less than a specified target level, and incentives for User Power Factors that are greater than the target level.
- 3.4.4.3 The Distribution Utility shall correct feeder and substation feeder bus Reactive Power Demand to a level, which will economically reduce feeder loss.

3.5 CUSTOMER SERVICE STANDARDS FOR DISTRIBUTION UTILITIES AND SUPPLIERS

3.5.1 Customer Service Standards

- 3.5.1.1 The Customer Service Standards for Distribution Utilities and Suppliers shall include:
 - (a) Guaranteed Standards; and

(b) Overall Standards.

3.5.1.2 Guaranteed Standards shall refer to the Customer Services where a penalty is imposed on the Distribution Utility (or Supplier) for failing to meet the target level of performance. The penalty is given to the affected Customer.

3.5.1.3 Overall Standards shall refer to the Customer Services where it is not appropriate to give a guarantee, but where the Customers have a right to expect the Distribution Utility (or Supplier) to deliver a reasonable level of service.

3.5.2 Measuring Customer Service Performance

3.5.2.1 The evaluation of the Customer Service performance of the Distribution Utility (or Supplier) shall include:

- (a) Prescriptive Approach; and
- (b) Customer Rating Approach.

3.5.2.2 In the Prescriptive Approach, the Distribution Utility (or Supplier) shall file an application with ERC for the approval of its Customer Service Program including the specified levels of performance or targets.

3.5.2.3 In the Customer Rating Approach, the Distribution Utility (or Supplier) shall commission an independent entity, accredited by the ERC, to conduct a Transactions Survey.

3.5.3 Customer Service Standards for Distribution Utilities

3.5.3.1 The Distribution Utility shall submit to ERC for approval the target levels for the Customer Services listed in Table 3-1. The Distribution Utility shall justify the basis for the target levels of performance.

3.5.3.2 The Distribution Utility shall be evaluated annually to compare its actual performance with the targets.

3.5.4 Customer Service Standards for Suppliers

3.5.4.1 The Supplier shall submit to the ERC for approval its target levels for the Customer Services listed in Table 3-2. The Supplier shall justify the basis for the target levels of performance.

3.5.4.2 The Supplier shall be evaluated annually to compare its actual performance with the targets.

3.5.4.3 The Customer Service Standards for Suppliers shall serve as a safety net that will protect the Customers during the early stages of the contestable market. Once the benefits of competition have been fully realized by the Customers, these standards may be withdrawn by the ERC.

TABLE 3-1
CUSTOMER SERVICE STANDARDS FOR DISTRIBUTION UTILITIES

Customer Service	Measure of Performance
1. Processing of application including estimates of charges	Number of days upon submission of complete requirements
2. Service connection	Number of days upon compliance with all government and Distribution Utility requirements
3. Restoration of service after a fault interruption on the secondary side, including service drop/lateral	Numbers of hours for 100% restoration
4. Power Quality complaints	a) Visit within x number of working days after receipt of complaint or substantive answer within y number of days; and b) Correction of Power Quality problems within z number of months
5. Informing Customers on schedule of power interruptions	Announcements x number of days prior to the scheduled interruptions
6. Responding to emergency calls	Response within x number of hours after receipt of call
7. Billing queries and complaints	a) Answer to queries within x number of hours; and b) Correction of errors in billing statement within y number of hours (or days)
8. Payment queries and complaints	a) Answer to queries within x number of hours; and b) Correction of errors in payments within y number of hours (or days)
9. Meter complaints	a) Visit within x number of working days after receipt of complaint or substantive answer within y number of days; and b) Correction of meter problems within z number of weeks
10. Reconnection of service	Reconnect within x hours after payment of all dues, provided payment is made before a specified cut-off time
11. Making and Keeping of appointments	a) Specific time is given to the Customer; and b) Seeing the Customer at the appointed time

**TABLE 3-2
CUSTOMER STANDARDS FOR SUPPLIERS**

Customer Service	Measure of Performance
1. Provision of supply and metering services	Within x number of days after agreement for supply has been made
2. Billing queries and complaints	a) Answer to queries within x number of hours; and b) Correction of errors in billing statement within y number of hours (or days)
3. Payment queries and complaints	a) Answer to queries within x number of hours; and b) Correction of errors in payments within y number of hours (or days)
4. Meter complaints	a) Visit within x number of working days after receipt of complaint or substantive answer within y number of days; and b) Correction of meter problems within z number of weeks
5. Reconnection of service	Reconnect within x hours after payment of all dues, provided payment is made before a specified cut-off time
6. Making and Keeping of appointments	a) Specific time is given to the Customer; and b) Seeing the Customer at the appointed time
7. Responding to Customer letters	Within x number of working days

3.6 SAFETY STANDARDS FOR DISTRIBUTION UTILITIES AND SUPPLIERS

3.6.1 Adoption of PEC and OSHS

3.6.1.1 The Distribution Utility shall develop, operate, and maintain its Distribution System in a safe manner and shall always ensure a safe work environment for its employees. In this regard, the ERC adopts the Philippine Electrical Code (PEC) Part 1 and Part 2 set by the Professional Regulation Commission and the Occupational Safety and Health Standards (OSHS) set by the Bureau of Working Conditions of the Department of Labor and Employment.

3.6.1.2 The PEC Parts 1 and 2 shall govern the safety requirements for electrical installation, operation, and maintenance. Part 1 of the PEC pertains to the wiring system in premises of End-Users. Part 2 covers electrical equipment and associated work practices employed by the Distribution Utility. Compliance with these codes is mandatory. Hence, the Distribution Utility and Supplier shall at all times ensure that all provisions of these safety codes are not violated.

3.6.1.3 The OSHS aims to protect every workingman against the dangers of injury, sickness, or death through safe and healthful working conditions.

3.6.2 Compliance with Republic Act No. 7920

Users of the Distribution System shall comply with the requirements of Section 33, Republic Act No. 7920 known as the “New Electrical Engineering Law”, the relevant implementing rules and regulations, and any amendments thereto, as applicable.

3.6.3 Measurement of Performance for Personnel Safety

Rule 1056 of the OSHS specifies the rules for the measurement of performance for personnel safety that applies to Distribution Utilities and Suppliers. The pertinent portions of this rule are reproduced as follows:

- (a) Exposure to work injuries shall be measured by the total number of hours of employment of all employees in each establishment or reporting unit.
- (b) Employee-hours of exposure for calculating work injury rates are intended to be the actual hours worked. When actual hours are not available, estimated hours may be used.
- (c) The Disabling Injury/Illness Frequency Rate shall be based upon the total number of deaths, permanent total, permanent partial, and temporary total disabilities, which occur during the period covered by the rate. The rate relates those injuries/illnesses to the employee-hours worked during the period and expresses the number of such injuries in terms of a million man-hour units.
- (d) The Disabling Injury/Illness Severity Rate shall be based on the total of all scheduled charges for all deaths, permanent total, and permanent partial disabilities, plus the total actual days of the disabilities of all temporary total disabilities, which occur during the period covered by the rate. The rate relates these days to the total employee-hours worked during the period and expresses the loss in terms of million man-hour units.

3.6.4 Submission of Safety Records and Reports

The Distribution Utility (or Supplier) shall submit to ERC copies of records and reports required by OSHS as amended. These shall include the measurement of performance specified in Section 3.6.3.

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CHAPTER 4

DISTRIBUTION CONNECTION REQUIREMENTS

4.1 PURPOSE AND SCOPE

4.1.1 Purpose

- (a) To specify the technical, design, and operational criteria at the User's Connection Point;
- (b) To ensure that the basic rules for connection to the Distribution System are fair and non-discriminatory for all Users; and
- (c) To list and collate the data required by the Distribution Utility from the User and to list the data to be provided by the Distribution Utility to the User.

4.1.2 Scope of Application

This Chapter does not apply to small retail Customers being provided bundled service by the Distribution Utility unless a Micro Embedded Generating Plant, as defined in Section 4.4.1, is connected to its premises. Such Customers shall be governed by the rules and procedures established by the Distribution Utility under its franchise, and in conformity with the applicable rules and regulations issued by the ERC.

4.2 DISTRIBUTION TECHNICAL, DESIGN, AND OPERATIONAL CRITERIA

4.2.1 Power Quality Standards

- 4.2.1.1 The Distribution Utility shall ensure that at any Connection Point in the Distribution System, the Power Quality standards specified in Article 3.2 are complied with.
- 4.2.1.2 The Embedded Generation Company shall ensure that the Power Quality standards specified in Section 4.4.5 are complied with.
- 4.2.1.3 Users of the Distribution System and Users seeking connection to the Distribution System or modification of an existing connection shall ensure that their Equipment can operate reliably and safely within the limits specified in Article 3.2 during normal conditions, and can withstand the limits specified in this Article.

4.2.2 Frequency Variations

- 4.2.2.1 The Distribution Utility shall design and operate its System to assist the System Operator in maintaining the system Frequency within the limits specified in Section 3.2.2.
- 4.2.2.2 The Embedded Generation Company shall in accordance with its corresponding classification, ensure that the standards for Frequency Variations for Large Conventional, Large VRE, Medium, Intermediate,

Small and Micro Embedded Generating Units are complied with as prescribed in Sections 4.5.2, 4.6.2, 4.7.2, 4.8.2, and 4.9.2, respectively.

4.2.2.3 In case the system Frequency momentarily rises to 62.4 Hz or falls to 57.6 Hz, all Embedded Generating Units shall remain in synchronism with the Grid for at least 5 seconds to allow the System Operator to undertake measures to correct the situation.

4.2.2.4 The Distribution Utility shall take into account the maximum estimated Frequency Variation during emergency conditions in the specification of distribution Equipment.

4.2.3 Voltage Variations

4.2.3.1 The Long Duration Voltage Variation at any Connection Point during normal conditions shall be within the limits specified in Section 3.2.3.

4.2.3.2 The Distribution Utility shall consider the maximum estimated Voltage Swell in the selection of the Voltage ratings of distribution Equipment.

4.2.3.3 Any extension or connection to the Distribution System shall be designed in such a way that it does not adversely affect the Voltage Variation in the Distribution System.

4.2.3.4 The Embedded Generation Company shall, following its classification, ensure that the standards for Voltage Variations for Large Conventional, Large VRE, Medium, Intermediate, Small and Micro Embedded Generating Units are complied with as prescribed in Subsections 4.5.1.2, 4.6.1.2, 4.7.1.2, 4.8.1.2, and 4.9.1.2, respectively.

4.2.4 Power Factor

4.2.4.1 The User shall maintain a Power Factor of not less than 85% lagging at the Connection Point in the Distribution System.

4.2.4.2 The Embedded Generation Company shall, following its classification, ensure that the standards for Power Factor for Large Conventional, Large VRE, Medium, Intermediate, Small and Micro Embedded Generating Units are complied with as prescribed in Sections 4.5.5, 4.6.3, 4.7.3, 4.8.3, and 4.9.3, respectively.

4.2.4.3 The Distribution Utility shall correct feeder and substation feeder bus Reactive Power Demand to a level that will economically reduce Technical Loss.

4.2.4.4 The Distribution Utility may establish incentives and penalties for User Power Factor at the Connection Point based on the target level.

4.2.5 Harmonics

4.2.5.1 The Total Harmonic Distortion of the Voltage and the Total Demand Distortion of the current, at any Connection Point, shall not exceed the limits prescribed in Section 3.2.4.

4.2.5.2 The User shall ensure that its System shall not cause the Harmonics in the Distribution System to exceed the limits specified in Section 3.2.4.

4.2.6 Voltage Unbalance

- 4.2.6.1 The maximum Voltage Unbalance at any Connection Point in the Distribution System shall not exceed the limits specified in Section 3.2.5 during normal operating conditions.
- 4.2.6.2 The User shall ensure that its System shall not cause the Voltage Unbalance in the Distribution System to exceed the limits specified in Section 3.2.5.

4.2.7 Flicker Severity

- 4.2.7.1 The Flicker Severity at any Connection Point in the Distribution System shall not exceed the limits specified in Section 3.2.6.
- 4.2.7.2 The User shall ensure that its System shall not cause the Flicker Severity in the Distribution System to exceed the limits specified in Section 3.2.6.
- 4.2.7.3 The Embedded Generation Company shall ensure that its System shall not cause the Flicker Severity in the Distribution System to exceed the limits specified in Subsection 4.4.5.1.

4.2.8 Transient Voltage Variations

- 4.2.8.1 The Distribution System and the User System shall be designed and operated to include devices that will mitigate the effects of transient Overvoltages on the Distribution System and the User System.
- 4.2.8.2 The Distribution Utility and the User shall take into account the effect of electrical transients when specifying the insulation of their electrical Equipment.

4.2.9 Protection Arrangements

- 4.2.9.1 The Distribution System shall be designed and operated with sufficient protection to ensure safety and to limit the Frequency and duration of Interruptions to End-Users.
- 4.2.9.2 The requirements for the protection system at the Connection Point shall be agreed upon by the Distribution Utility and the User during the application for connection or modification of an existing connection and shall be reviewed from time to time by the Distribution Utility, with the concurrence of the User.
- 4.2.9.3 The User System shall be designed and operated with protective devices following with the requirements of the Distribution Utility.
- 4.2.9.4 Unless the Distribution Utility instructs otherwise, the User shall not use current-limiting protective devices to limit the fault current infeed to the Distribution System.
- 4.2.9.5 The Fault Clearance Time shall be within the limits established by the Distribution Utility in accordance with the protection policy adopted for the Distribution System.

4.2.9.6 The Distribution Utility shall provide the details of any autoreclosing or sequential switching features in the Distribution System so that the User may take this into account in the design of its protection system.

4.2.9.7 The User shall consider in the design of its protection system the possible Disconnection of only one phase or two phases during fault conditions.

4.2.9.8 The Embedded Generation Company shall, following its classification, ensure that the standards for protection arrangements for Large Conventional, Large VRE, Medium, Intermediate, Small and Micro Embedded Generating Units are complied with as prescribed in Section 4.5.9, 4.6.7, 4.7.6, 4.8.6, and 4.9.5.

4.2.10 Equipment Short Circuit Rating

4.2.10.1 The Distribution Utility shall inform the User of the designed and existing Fault Levels of the Distribution System at the Connection Point.

4.2.10.2 The User shall consider the designed and existing Fault Levels at the Connection Point in the design and operation of the User System.

4.2.11 Grounding Requirements

4.2.11.1 The Distribution Utility shall inform the User of the Grounding method used in the Distribution System. The specification of Distribution Equipment shall consider the maximum Voltage Swell that will be imposed on the Equipment during faults involving ground.

4.2.11.2 The method of Grounding at the User System shall comply with the Grounding standards and specifications of the Distribution Utility.

4.2.11.3 Where there are multiple sources of power, the User shall ensure that the effects of circulating currents with respect to the grounded neutral are either prevented or mitigated.

4.2.12 Monitoring and Control Equipment Requirements

4.2.12.1 The Distribution Utility and the User shall agree on the mode of monitoring and control.

4.2.12.2 The Distribution Utility shall provide, install, and maintain the telemetry outstation and all associated Equipment needed to monitor the User System.

4.2.12.3 If the User agrees that the Distribution Utility shall control the switchgear in the User System, the Distribution Utility shall install the necessary control outstation, including the control interface for the switchgear.

4.2.13 Equipment Standards

4.2.13.1 All Equipment at the Connection Point shall comply with the requirements of international standards (e.g., ANSI/IEEE, IEC).

4.2.13.2 All Equipment at the Connection Point shall be designed, manufactured, and tested in accordance with international standards (e.g., ANSI/IEEE, IEC).

4.2.13.3 The prevailing standards at the time when the Connection Point was designed or modified, rather than the Test and Commissioning date or the asset transfer date, shall apply to all Equipment at the Connection Point.

4.2.14 Maintenance Standards

4.2.14.1 All Equipment at the Connection Point shall be operated and maintained in accordance with international standards (*e.g.*, ANSI/IEEE, IEC) and in a manner that shall not pose a threat to the safety of any personnel or cause damage to the Equipment of the Distribution Utility or the User.

4.2.14.2 The Distribution Utility shall maintain a log containing the test results and maintenance records relating to its Equipment at the Connection Point and shall make this log available when requested by the User.

4.2.14.3 The User shall maintain a log containing the test results and maintenance records relating to its Equipment at the Connection Point and shall make this log available when requested by the Distribution Utility.

4.3 PROCEDURES FOR DISTRIBUTION CONNECTION OR MODIFICATION

4.3.1 Connection Agreement

4.3.1.1 Any User seeking a new connection to the Distribution System shall secure the required Connection Agreement with the Distribution Utility prior to the actual connection to the Distribution System.

4.3.1.2 The Connection Agreement shall include provisions for the submission of information and reports, Safety Rules, Test and Commissioning programs, Electrical Diagrams, statement of readiness to connect, certificate of approval to connect, and other requirements prescribed by the ERC.

4.3.2 Amended Connection Agreement

4.3.2.1 Any User seeking to modify an existing connection to the Distribution System shall secure the required Amended Connection Agreement with the Distribution Utility prior to the actual modification.

4.3.2.2 The Amended Connection Agreement shall include provisions for the submission of additional information required by the Distribution Utility and prescribed by the ERC.

4.3.3 Distribution Impact Studies

4.3.3.1 The Distribution Utility shall develop and maintain a set of required technical studies for evaluating the impact on the Distribution System of any proposed connection or modification to an existing connection.

4.3.3.2 The technical studies required under Section 4.3.3.1 shall be completed within the period as prescribed by the ERC. The Distribution Utility shall treat this period as the maximum acceptable impact study duration. In cases where the Distribution Utility is unable to complete the Distribution Impact Study within the time period specified, it shall notify

the User and provide an estimated date of completion with a justification or explanation for the requirement of additional Completion Date.

4.3.3.3 The User shall indicate in its application whether it wishes the Distribution Utility to undertake additional technical studies. The User shall shoulder the additional cost for the additional technical studies to be conducted.

4.3.3.4 To enable the Distribution Utility to carry out the necessary detailed Distribution Impact Studies, the User may be required to provide some or all of the Detailed Planning Data listed in Article 5.5 ahead of the normal timescale referred to in Section 4.3.6.

4.3.3.5 Any User applying for connection or a modification of an existing connection to the Distribution System shall take all necessary measures to ensure that its proposed connection or modification shall not result in the Degradation of the Distribution System.

4.3.3.6 The Distribution Utility shall conduct Distribution Impact Studies to evaluate the impact of the proposed connection or modification to an existing connection in the Distribution System. The evaluation shall include the following:

- (a) Power flows, both in Normal State and in case of contingencies, to ensure that the Distribution System can properly accommodate the flows of both the Embedded Generation Plants and existing loads;
- (b) Voltage Control studies, to ensure that Voltage can be properly maintained within the prescribed limits;
- (c) Impact of short circuit infeed to the Distribution Equipment in order to verify that the Equipment limits are not exceeded;
- (d) Definition and coordination of protection system; and
- (e) Impact of User Development on Power Quality.

4.3.3.7 In the case of Embedded Generating Plants with capacity of 10MW and above for Luzon, and 5MW and above for Visayas and Mindanao, the Distribution Utility upon receipt of the application for connection, shall inform the Transmission Network Provider about the application for connection of the User. The Transmission Network Provider will assess the application. Certain conditions or special requirements, if any, shall be clearly stated and justified by the Transmission Network Provider for compliance of the User.

The Distribution Utility shall formally inform the User of the results of the Distribution Impact Study as well as the assessment made by the Transmission Network Provider, if any.

4.3.3.8 For Medium Embedded Generating Plants as defined in Section 4.4.1 and connected to an HV/MV substation through a Dedicated Feeder, the total Installed Capacity of the Medium Embedded Generating Plant requesting connection plus the aggregated capacity of all other Embedded Generating Plants connected to the substation and regardless of their type shall not exceed the Minimum Load of the HV/MV Transformer at the substation. In case there are no registers of such Minimum Load, the value will be estimated as 25% of the Transformer rated capacity.

- 4.3.3.9 For (i) Intermediate Embedded Generating Plants, or (ii) Medium Embedded Generating Plants lower than two MW as defined in Section 4.4.1 and connected to an existing MV feeder with other Customers connected, following rules shall apply:
- (a) The total Installed Capacity of the Intermediate or Medium Embedded Generating Plant requesting connection plus the aggregated capacity of all other Embedded Generating Plants connected to the same feeder, regardless of their types, shall not exceed 30% of the rated capacity of the MV feeder.
 - (b) The total Installed Capacity of the Medium Embedded Generating Plant requesting connection plus the aggregated capacity of all other Embedded Generating Plants, regardless of their type, connected to the substation to which the MV feeder is connected, shall not exceed the Minimum Load in a year of the HV/MV Transformer at the substation. In case there are no registers of such Minimum Load, the value will be estimated as 25% of the Transformer rated capacity.
 - (c) The maximum Voltage changes at the Connection Point due to the switching operation of the Medium or Intermediate Embedded Generating Plant shall not exceed 2% of the nominal Voltage.
- 4.3.3.10 For Small Embedded Generating Units as defined in Section 4.4.1, the following rules shall apply to the requested connection:
- (a) In cases of connection to an existing LV feeder with other Customers connected, the total installed capacity of the Small Embedded Generating Unit requesting connection plus the aggregated capacity of all other Embedded Generating Units regardless of their type and connected to the feeder, shall not exceed 30% of the rated capacity of the LV feeder.
 - (b) The total Installed Capacity of the Small Embedded Generating Unit requesting connection plus the aggregated capacity of all other Embedded Generating Units regardless of their type and connected to the busbar of the MV/LV substation, shall not exceed one third of the rated capacity of the MV/LV Transformer.
 - (c) The maximum Voltage changes at the Connection Point due to the switching operation of the Small Embedded Generating Units shall not exceed 2% of the nominal Voltage.
- 4.3.3.11 In case Subsections 4.3.3.8, 4.3.3.9 or 4.3.3.10, as it corresponds, do not apply or in cases the conditions stated in such sections are not fulfilled, the Distribution Utility may request conducting a more detailed Distribution Impact Study in order to decide about the acceptance or rejection of the requested connection. In this case the Distribution Utility is entitled to impose additional requirements other than those stated in Section 4.4 in order to allow the connection of the Embedded Generating Plants or Units to the Distribution System.
- 4.3.3.12 For Micro Embedded Generating Units as defined in Section 4.4.1, it should be determined before connection that:
- (a) The Micro Embedded Generating Unit and all other associated equipment to be installed have been Type Tested safe and to cause no

unwanted disturbance to the Distribution System. The project proponent shall submit to the Distribution Utility the Type Tests Report.

- (b) The total amount of Small and Micro Embedded Generating Units connected to the LV feeder shall not exceed 30% of the rated capacity of distribution Transformer.

4.3.3.13 The Distribution Utility may disapprove an application for connection or a modification of an existing connection to the Distribution System if it is determined through the Distribution Impact Studies that the proposed connection or modification will result in the Degradation of the Distribution System.

4.3.4 Application for Connection or Modification

4.3.4.1 Any User applying for connection or modification of an existing connection to the Distribution System shall submit to the Distribution Utility the completed application form for connection or modification of an existing connection to the Distribution System. The application form shall include the following information:

- (a) A description of the proposed connection or modification to an existing connection, which shall comprise the User Development at the Connection Point;
- (b) The relevant Standard Planning Data listed in Article 5.4; and
- (c) The Completion Date of the proposed User Development.

4.3.4.2 The User shall submit the planning data in three stages, according to their degree of commitment and validation as described in Section 4.14.2. These include:

- (a) Preliminary Project Planning Data;
- (b) Committed Project Planning Data; and
- (c) Connected Project Planning Data.

4.3.5 Processing of Application

4.3.5.1 The Distribution Utility shall establish the procedure for the processing of applications for connection or modification of an existing connection to the Distribution System.

4.3.5.2 The Distribution Utility shall process the application for connection or modification to an existing connection within 30 days from the submission of the completed application form.

4.3.5.3 The Distribution Utility shall evaluate the impact of the proposed User Development on the Distribution System.

4.3.5.4 After evaluating the application submitted by the User, the Distribution Utility shall inform the User whether the proposed User Development is acceptable or not.

4.3.5.5 If the application of the User is acceptable, the Distribution Utility and the User shall sign a Connection Agreement or an Amended Connection Agreement, as the case may be.

- 4.3.5.6 If the application of the User is not acceptable, the Distribution Utility shall inform the User of the reasons why its application is not acceptable. The Distribution Utility shall include in the notice a proposal to make the User's application acceptable to the Distribution Utility.
- 4.3.5.7 The User is given 30 days to accept the proposal of the Distribution Utility or within a longer period specified in the notice provided by the Distribution Utility, after which period the proposal shall automatically lapse.
- 4.3.5.8 The acceptance by the User of the Distribution Utility's proposal shall lead to the signing of a Connection Agreement or an Amended Connection Agreement.
- 4.3.5.9 If the Distribution Utility and the User cannot reach agreement on the proposed connection or modification to an existing connection, the Distribution Utility or the User may bring the matter before the ERC for resolution.
- 4.3.5.10 If a Connection Agreement or an Amended Connection Agreement is signed and within 30 days from signing thereof or within such longer period as may be agreed upon by the Distribution Utility and the User, the User shall submit to the Distribution Utility the Detailed Planning Data of the proposed User Development as specified in Article 5.5.

4.3.6 Submittals Prior to the Commissioning Date

The following shall be submitted by the User prior to the commissioning date, pursuant to the terms and conditions and schedules specified in the Connection Agreement:

- (a) Specifications of major Equipment not included in the Standard Planning Data and Detailed Planning Data;
- (b) Details of the protection arrangements, its settings and communication link setup as referred to in Subsection 4.2.9.8 for Embedded Generating Units and in Section 4.10.2 for other Users;
- (c) Information to enable the Distribution Utility to prepare the Fixed Asset Boundary Document referred to in Article 4.11 including the names of Accountable Persons;
- (d) Electrical Diagrams of the User's Equipment at the Connection Point as described in Article 4.12;
- (e) Information that will enable the Distribution Utility to prepare the Connection Point Drawings, referred to in Article 4.13;
- (f) Copies of all Safety Rules and Local Safety Instructions applicable to the User's Equipment and a list of Safety Coordinators, pursuant to the requirements of Article 6.8;
- (g) A list of the names and telephone numbers of authorized representatives, including the confirmation that they are fully authorized to make binding decisions on behalf of the User, for Significant Incidents pursuant to the procedures specified in Section 6.7.2;
- (h) Proposed Maintenance Program; and

- (i) Test and Commissioning procedure for the Connection Point and the User Development.

4.3.7 Commissioning of Equipment and Physical Connection to the Distribution System

- 4.3.7.1 Upon completion of the User Development, including work at the Connection Point, the Equipment at the Connection Point and the User Development shall be subjected to the Test and Commissioning procedure specified in Section 4.3.6.
- 4.3.7.2 The User shall then submit to the Distribution Utility a statement of readiness to connect, which shall include the Test and Commissioning report and the result of the capability test.
- 4.3.7.3 Upon acceptance of the User's statement of readiness to connect, the Distribution Utility shall, within 15 days, issue a certificate of approval to connect.
- 4.3.7.4 The physical connection to the Distribution System shall be made only after the certificate of approval to connect has been issued by the Distribution Utility to the User.

4.4 REQUIREMENTS FOR ALL EMBEDDED GENERATION COMPANIES

4.4.1 Classification of Embedded Generating Plants

The Embedded Generating Plant shall be classified according to its characteristics and Installed Capacity, as provided by Table 4-1.

TABLE 4-1
CLASSIFICATION OF EMBEDDED GENERATING PLANTS

Category	Installed Capacity and Characteristics
Large Conventional	Conventional Embedded Generating Plant with an aggregated Installed Capacity of 10 MW or more.
Large VRE	VRE Embedded Generating Plant with an aggregated Installed Capacity of 10 MW or more.
Medium	Conventional or VRE Embedded Generating Plants with Installed Capacity larger than 1 MW which do not qualify as Large Embedded Generating Plant.
Intermediate	Conventional or VRE Embedded Generating Plants with Installed Capacity larger than 100 kW and equal to or less than 1 MW; and Conventional Embedded Generating Plants with Installed Capacity lower or equal to 100 kW connected to MV networks.
Small	Embedded Generating Plant with Installed Capacity larger than 10 kW and equal to or less than 100 kW connected to LV networks.
Micro	Embedded Generating Plants with Installed Capacity lower or equal to 10 kW connected to LV networks.

4.4.2 Requirements Relating to the Connection Point

- 4.4.2.1 The Equipment of the Embedded Generation Company shall be connected to the Distribution System at the Voltage level agreed to by the Distribution Utility and the Embedded Generation Company based on the Distribution Impact Studies.
- 4.4.2.2 The Connection Point shall be controlled by a Circuit Breaker that is capable of interrupting the maximum short circuit current at the point of connection.
- 4.4.2.3 Disconnect switches, or other isolating means, shall also be provided and arranged to isolate the Circuit Breaker for maintenance purposes.

4.4.3 Black Start Capability

- 4.4.3.1 The Embedded Generation Company shall specify in its application for Connection Agreement or Amended Connection Agreement if its Generating Unit has a Black Start capability.
- 4.4.3.2 The Embedded Generating Unit providing Ancillary Services for Black Start shall be capable of initiating a Black Start procedure in accordance with Section 6.7.4.

4.4.4 Fast Start Capability

- 4.4.4.1 The Embedded Generation Company shall specify in its application for a Connection Agreement or Amended Connection Agreement if its Generating Unit has a Fast Start capability.
- 4.4.4.2 The Embedded Generating Unit providing Ancillary Services for Fast Start shall automatically Start-Up in response to frequency-level relays with settings in the range of 57.6 Hz to 62.4 Hz.

4.4.5 Power Quality

- 4.4.5.1 With the System in Normal State, upon the connection of the Embedded Generating Plant, the Flicker Severity at the Connection Point shall not exceed the values established in Section 3.2.6. The maximum long-term Flicker introduced by an Embedded Generating Plant shall be determined as the maximum allowed Flicker at the Connection Point, multiplied by the ratio of the Embedded Generating Plant's Installed Capacity to the total capacity of all other interference sources connected at the same Connection Point.
- 4.4.5.2 Upon the connection of Embedded Generating Plant, the Total Harmonic Distortion (THD) of the Voltage and the Total Demand Distortion (TDD) of the current at the Connection Point shall not exceed the limits established in Section 3.2.4. The maximum harmonic current injection from an Embedded Generating Plant to the Grid shall be determined as the maximum allowed harmonic current injection at the Connection Point, multiplied by the ratio of Embedded Generating Plant's Installed Capacity to the total capacity of all power generation/supply Equipment with harmonic source at the Connection Point.
- 4.4.5.3 The Embedded Generating Company shall comply with the following permissible voltage fluctuation limits at the Connection Point:
- (a) Voltage fluctuation limit for step changes which may occur repetitively is 1%.
 - (b) Voltage fluctuation limit for occasional fluctuations other than step changes is 3%.
- For clarity, these limits apply to any possible fluctuation in Voltage caused by any kind of switching operations (i.e. capacitor banks, start/stop of Embedded Generating Units, inrush currents during Embedded Generating Plants connection) and/or by any kind of fluctuation of the primary Energy in case of VRE Embedded Generating Plants.
- 4.4.5.4 The Embedded Generating Company shall demonstrate to the Distribution Utility that the Embedded Generating Plant facilities installed comply with the prescriptions indicated in Subsections 4.4.5.1 to 4.4.5.3 through a certification issued by the Manufacturer, stating that its Embedded Generating Units have been tested and certified in a reputable laboratory showing compliance with the stated requirements. A copy of the laboratory certification should be attached to the certification issued by the Manufacturer. In case such certification is not available, specific tests shall be performed in order to assess compliance.

4.4.6 Transformer Connection and Grounding

- 4.4.6.1 The Distribution Utility shall specify the connection and grounding requirements for the Transformer, in accordance with Section 4.2.11.
- 4.4.6.2 Where there are multiple sources of power, the Embedded Generation Company shall ensure that the effects of circulating currents with respect to the grounded neutral are either prevented or mitigated.

4.5 REQUIREMENTS FOR LARGE CONVENTIONAL EMBEDDED GENERATING PLANTS

4.5.1 Embedded Generating Unit Power Output

- 4.5.1.1 The Large Conventional Embedded Generating Unit shall be capable of continuously supplying its Active Power output, as specified in the Generation Company's Declared Data, within the system Frequency range of 59.7 to 60.3 Hz. Any decrease of power output occurring in the Frequency range of 59.7 to 57.6 Hz shall not be more than the required proportionate value of the system Frequency decay.
- 4.5.1.2 The Large Conventional Embedded Generating Unit shall be capable of supplying its Active Power output and the interchange of Reactive Power at the Connection Point, as specified in the Generation Company's Declared Data, within the Voltage Variation of $\pm 5\%$ during normal operating conditions. Outside this range and up to a Voltage Variation specified in Section 4.2.3, a reduction on Active Power and/or Reactive Power can be allowed, provided that this reduction does not exceed 5% of the Generation Company's Declared Data.

4.5.2 Frequency Withstand Capability

- 4.5.2.1 If the system Frequency momentarily rises to 62.4 Hz or falls to 57.6 Hz, a Large Conventional Embedded Generating Unit shall remain in synchronism with the Grid for at least 5 seconds, as specified in Section 4.2.2. The Distribution Utility, in consultation with the System Operator, may waive this requirement, if there are sufficient technical reasons to justify the waiver.
- 4.5.2.2 The Large Conventional Embedded Generating Unit shall be capable to operate, for at least 5 minutes, in case of increase in Frequency within the range of 61.8 to 62.4 Hz; and for at least 60 minutes, in case of a decrease in Frequency within the range of 57.6 to 58.2 Hz, in both cases provided the Voltage at the Connection Point is within $\pm 10\%$ of the nominal value.
- 4.5.2.3 The Embedded Generation Company shall be responsible for protecting its Embedded Generating Units against damage for Frequency excursions outside the range of 57.6 Hz and 62.4 Hz. The Embedded Generation Company shall decide whether or not to disconnect its Embedded Generating Plant from the Distribution System.
- 4.5.2.4 The Large Conventional Embedded Generating Unit shall remain Synchronized during a rate of change of Frequency of values up to and including ± 1 Hz per second measured as a rolling average over 500

milliseconds. As voltage dips may cause localized rate of change of Frequency values in excess of 1 Hz per second for short periods, the Large Conventional Embedded Generating Unit shall remain Synchronized for at least 600 milliseconds for voltage dips at the Connection Point up to 95% (Voltage at the Connection Point larger than 5%).

4.5.3 Unbalance Loading Withstand Capability

The Large Conventional Embedded Generating Unit shall meet the requirements for Voltage Unbalance as specified in Section 4.2.6.

4.5.4 Performance Under Disturbances

The Large Conventional Embedded Generating Unit shall also be required to withstand without tripping, the Voltage Sags on unbalance loading during clearance by the Backup Protection of a close-up phase-to-phase fault on the Distribution System.

4.5.5 Reactive Power Capability

The Large Conventional Embedded Generating Unit shall be capable of supplying its Active Power output, as specified in the Generation Company's Declared Data, within the limits of 85% Power Factor lagging and 90% Power Factor leading at the Large Conventional Embedded Generating Plant's Connection Point, in accordance with its Reactive Power Capability Curve.

4.5.6 Reactive Power Control and Excitation Control System

4.5.6.1 The Large Conventional Embedded Generating Plant shall be capable of contributing to Voltage Control by continuous regulation of the Reactive Power supplied to the Distribution System in any of the following modes, as determined by the Distribution Utility, and provided the limits of Reactive Power output established in Section 4.5.5 are not exceeded:

- (a) Maintain a constant Reactive Power injection/absorption at the Connection Point, at a value prescribed by the Distribution Utility;
- (b) Maintain a constant Power Factor of the injected Energy at the Connection Point, at a value prescribed by the Distribution Utility; or
- (c) Maintain the Voltage at the HV busbar of the Large Conventional Embedded Generating Plant, at a set point instructed by the Distribution Utility.

4.5.6.2 In order to comply with the requirements established in Subsection 4.5.6.1, the Large Conventional Embedded Generating Unit shall be equipped with a continuously acting automatic excitation control system to control the terminal Voltage without instability over the entire operating range of the Generating Unit.

4.5.6.3 When necessary for system operations, the performance requirement for excitation control facilities including power system stabilizers shall be specified in the Connection Agreement or Amended Connection Agreement.

4.5.7 Active Power Control

- 4.5.7.1 The Large Conventional Embedded Generating Unit shall be fitted with a fast-acting speed-governing system. The speed-governing system shall have an overall speed-droop characteristic of 5% or less.
- 4.5.7.2 During Island Grid operation, a Large Conventional Embedded Generating Unit providing Ancillary Services for Black Start Capability shall provide Frequency Control to the Island Grid.

4.5.8 Speed-Governing System

- 4.5.8.1 In cases of Conventional Embedded Generation Companies, the Embedded Generating Unit providing Ancillary Services for Primary Reserve shall operate in Governor Control Mode.
- 4.5.8.2 The Embedded Generating Unit providing Ancillary Services for Secondary Reserve shall operate in AGC. The speed-governing system shall be capable of accepting raise and lower signals from the Distribution Utility or the System Operator.

4.5.9 Protection Arrangements

- 4.5.9.1 The protection of Large Conventional Embedded Generating Units and Equipment and their connection to the Distribution System shall be designed, coordinated, and tested to achieve the desired level of speed, sensitivity, and selectivity in fault clearing as well as in other system troubles, and to minimize their impact to the Distribution System. In particular, the Large Conventional Embedded Generation Company shall agree with the Distribution Utility on the protection measures required to prevent unintended islanding operation.
- 4.5.9.2 The Distribution Utility and the Large Conventional Embedded Generation Company shall be responsible separately, for the protection system of the electrical Equipment and facilities at their respective sides of the Connection Point.

4.5.10 Information Interchange

- 4.5.10.1 A communication system shall be established so that the System Operator, the Distribution Utility and Large Conventional Embedded Generation Company can communicate with one another. During normal and emergency conditions, the System Operator through the Distribution Utility shall communicate with the Embedded Generation Company.
- 4.5.10.2 The Large Conventional Embedded Generation Company shall provide the RTU and complete communication Equipment required for the monitoring and control of the Connection Point and the Embedded Generating Units with the Distribution Utility. Large Conventional Embedded Generation Companies which are registered in the WESM shall comply with the communication Equipment required under the WESM rules and the latest edition of the Philippine Grid Code, where applicable.
- 4.5.10.3 The following information shall be sent to the Distribution Utility and as appropriate to the Transmission Network Provider:

- (a) Operation status of the Large Conventional Embedded Generation Plant;
- (b) Voltage at HV busbar of the Large Conventional Embedded Generating Plant;
- (c) Active Power, Reactive Power and electric current at HV side of step-up Transformer of the Large Conventional Embedded Generating Plant; and
- (d) Status of HV circuit breakers and isolator switches.

The Distribution Utility, if necessary, may furnish the above information to the System Operator.

4.5.10.4 The Distribution Utility and the Large Conventional Embedded Generation Company may agree on the provision of additional signals, in which case, such agreement shall be reflected in the Connection Agreement or Amended Connection Agreement.

4.6 REQUIREMENTS FOR LARGE VRE EMBEDDED GENERATING PLANTS

4.6.1 Embedded Generating Unit Power Output

4.6.1.1 The Large VRE Embedded Generating Unit shall be capable of continuously supplying its Active Power output, depending on the availability of the primary resource, and its Reactive Power output within the power system Frequency range of 59.7 to 60.3 Hz.

4.6.1.2 The Large VRE Embedded Generating Unit shall be capable of supplying its Active Power output depending on the availability of the primary resource and the interchange of Reactive Power at the Connection Point as specified in Section 4.6.3 within the Voltage Variation of $\pm 5\%$ during normal operating conditions. Outside this range, and up to a Voltage Variation of $\pm 10\%$, a reduction on Active Power and/or Reactive Power can be allowed, provided that this reduction does not exceed 5% of the Generation Company's Declared Data.

4.6.2 Frequency Withstand Capability

4.6.2.1 Any variation of the power system Frequency within the range of 58.2 Hz to 61.8 Hz should not cause the Disconnection of the Large VRE Embedded Generating Unit.

4.6.2.2 The Large VRE Embedded Generating Unit shall be capable to operate for at least 5 minutes, in case of an increase in Frequency within the range of 61.8 to 62.4 Hz; and for at least 60 minutes, in case of a decrease in Frequency within the range of 57.6 to 58.2 Hz, provided that in both cases the Voltage at the Connection Point is within $\pm 10\%$ of the nominal value.

4.6.2.3 The Large VRE Generation Company shall be responsible for protecting its Large VRE Embedded Generating Unit against damage from Frequency excursions outside the range of 57.6 Hz and 62.4 Hz; Provided that in case the Frequency momentarily falls below 57.6 Hz the Large VRE Embedded Generating Unit shall remain connected for at least 5

seconds. In case of an increase in Frequency above 62.4 Hz, the Large VRE Embedded Generation Company shall decide whether or not to disconnect the Embedded Generating Plant and/or its Embedded Generating Units from the Grid.

4.6.2.4 The Large VRE Embedded Generating Unit shall remain Synchronized during a rate of change of Frequency of values up to and including ± 1 Hz per second measured as a rolling average over 500 milliseconds. As voltage dips may cause localized rate of change of Frequency values in excess of ± 1 Hz per second for short periods, the Large VRE Embedded Generating Unit shall remain Synchronized if the voltage dips at the Connection Point are within the values established in Section 4.6.6.

TABLE 4-2
REQUIREMENTS FOR DIFFERENT FREQUENCY RANGES – LARGE VRE EMBEDDED GENERATING PLANTS

Frequency		Time
Hz	p.u.	
> 62.4	> 1.04	Automatic disconnection is discretionary upon the VRE Embedded Generation Company
> 61.8 – 62.4	> 1.03 – 1.04	5 minutes
58.2 – 61.8	0.97 - 1.03	Continuous Operation
57.6 - < 58.2	0.96 - < 0.97	60 minutes
< 57.6	< 0.96	5 seconds

4.6.3 Reactive Power Capability

4.6.3.1 The Large VRE Embedded Generating Plant shall be capable of supplying Reactive Power output, at its Connection Point, within the following ranges:

- (a) $\pm 20\%$ of its Embedded Generating Plant Capacity as specified in the Generation Company’s Declared Data, if its Active Power output depending on the availability of the primary resource, is equal to or above 58% of the Embedded Generating Plant Installed Capacity;
- (b) Any Reactive Power value within the limits of 95% Power Factor lagging to 95% Power Factor leading, if its Active Power output depending on the availability of the primary resource, is within the 10% and 58% of the Embedded Generating Plant Installed Capacity;
- (c) No Reactive Power interchange if the Active Power output depending on the availability of the primary resource, is equal to or less than 10% of the Embedded Generating Plant Installed Capacity.

4.6.4 Reactive Power Control

4.6.4.1 The Large VRE Embedded Generating Plant shall be capable of contributing to Voltage Control by continuous regulation of the Reactive Power supplied to the Distribution System in any of the following modes

as determined by the Distribution Utility, and provided the limits of Reactive Power output established in Section 4.6.3 are not exceeded:

- (a) Maintain a constant Power Factor of the injected energy at the Connection Point at a value prescribed by the Distribution Utility; or
- (b) Maintain the Voltage at the Connection Point of the Large VRE Embedded Generating Plant, at a set point instructed by the Distribution Utility.

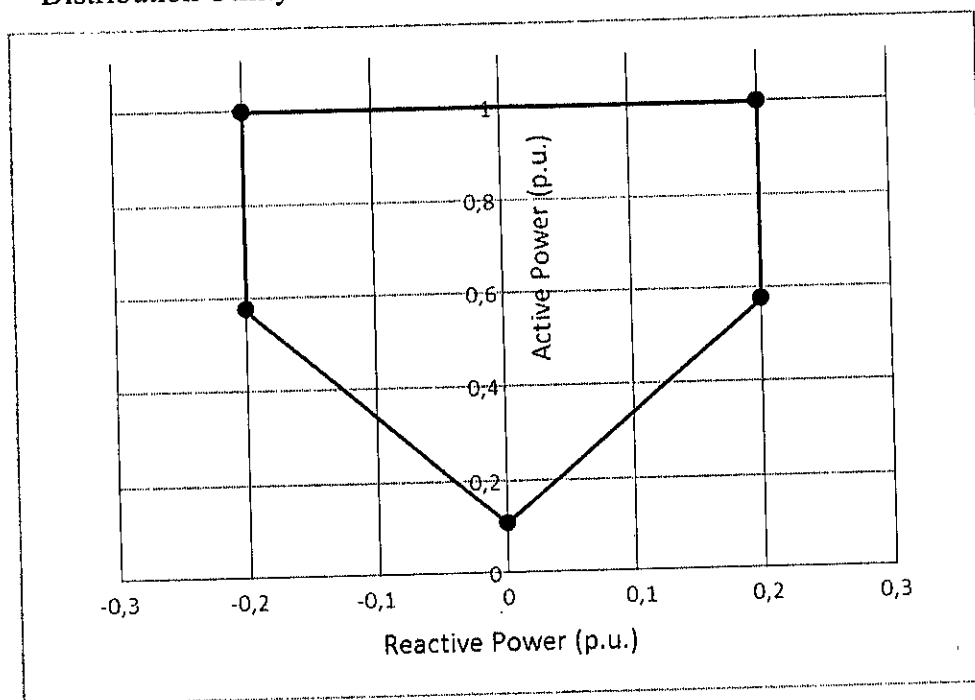


FIGURE 4-1
REACTIVE POWER REQUIREMENTS – LARGE VRE EMBEDDED GENERATING PLANTS

4.6.4.2 In order to comply with the requirements established in Subsection 4.6.4.1, the Large VRE Embedded Generating Plant shall be equipped with an appropriate control system to control Voltage/Reactive Power interchange over the entire operating range, which shall not create oscillations in the network.

4.6.5 Active Power Control

4.6.5.1 Large VRE Embedded Generating Plants should be equipped with an active power regulation control system to operate, at least in the following control modes, and provided that system frequency is within the range of 59 to 61 Hz:

- (a) Free Active Power production (no Active Power control): The Large VRE Embedded Generating Plant should operate and produce maximum Active Power output depending on the availability of the primary resource.
- (b) Active Power constraint: The Large VRE Embedded Generating Plant should operate and produce Active Power output equal to a value specified by the System Operator (set-point), provided the availability of the primary resource is equal to or higher than the prescribed value,

or producing maximum possible Active Power in case the primary resource availability is lower than the prescribed set point.

4.6.5.2 In cases wherein the Large VRE Embedded Generating Plant operates in Active Power constraint, whenever any control parameter is changed, such change must be commenced within 2 seconds and completed not later than 30 seconds after receipt of an order to change any parameter. The accuracy of the control performed must be within $\pm 2\%$ of the entered value or by $\pm 0.5\%$ of the rated power, depending on which yields the highest tolerance.

4.6.5.3 In case the System Frequency exceeds 61 Hz, the Active Power control system should reduce the Active Power previously generated following the formula below:

$$\Delta P = 45 \cdot P_m \cdot \left(\frac{61.0 - f_n}{60} \right)$$

Where:

ΔP : is the variation in Active Power output that should be achieved

P_m : is the Active Power output before this control is activated

f_n : is the network Frequency

The reduction in Active Power output shall be performed at the maximum possible gradient, provided the technical capabilities of the Large VRE Embedded Generating Units are not exceeded.

If the Active Power for any Large VRE Embedded Generating Unit is regulated downward below its Minimum Technical Load (P_{\min}), shutting-down of individual Large VRE Embedded Generating Unit is allowed.

4.6.5.4 In case system Frequency drops below 59 Hz, the Active Power control system should change to free Active Power production mode, generating the maximum possible Active Power output compatible with the availability of the primary resource.

4.6.5.5 The actions specified in Subsections 4.6.5.3 and 4.6.5.4 should be performed automatically, unless:

- (a) The System Operator considers that the control system proposed by the Large VRE Embedded Generation Company, although not automatic, is enough for the operation of the system, taking into account (i) the characteristics of the Large VRE Embedded Generating Plant, including its size and location; and (ii) Power System current situation and its probable future evolution; or
- (b) The System Operator instructs the Large VRE Embedded Generation Company to disable this mode of control.

4.6.6 Performance During Network Disturbances

4.6.6.1 The Large VRE Embedded Generating Unit shall be able to withstand Voltage Sag at the Connection Point without disconnection, produced by fault or disturbances in the network, which magnitude and duration

profiles are within the shaded area in Figure 4-2. This area is defined by the following characteristics:

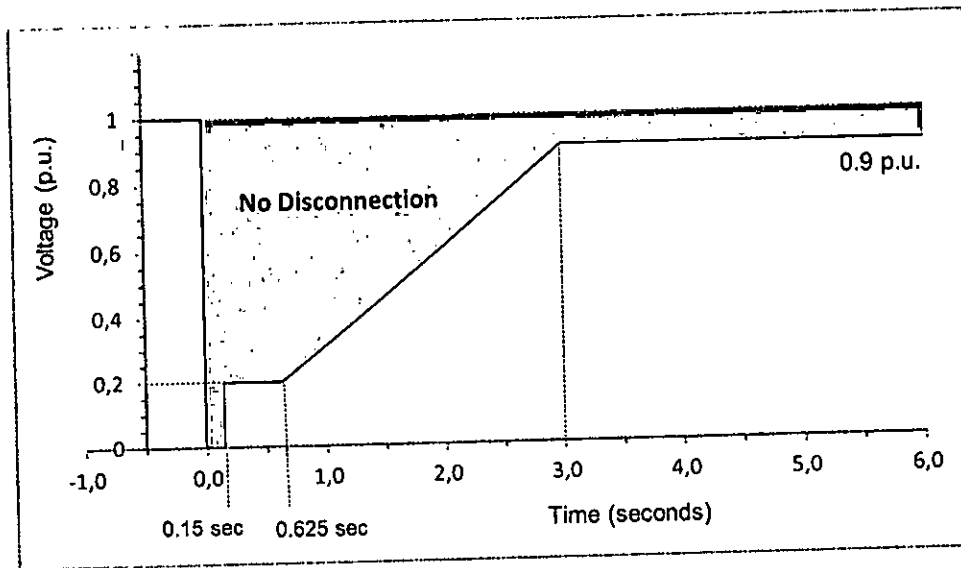


FIGURE 4-2
LOW VOLTAGE WITHSTAND CAPABILITY – LARGE VRE EMBEDDED GENERATING UNITS

- (a) If the Voltage at the Connection Point falls to below 20% of nominal value, the Large VRE Embedded Generating Unit shall remain connected for at least 0.15 seconds;
- (b) If the Voltage at the Connection Point falls but it is still above 20% of the nominal value, in all the three phases, the Large VRE Embedded Generating Unit shall remain connected for at least 0.625 seconds;
- (c) If the Voltage at the Connection Point is equal or above 90% of the nominal value, in all the three phases, the Large VRE Embedded Generating Unit shall remain connected indefinitely, up to fault clearance;
- (d) For Voltages between 20% and 90% of the nominal value, the time the Large VRE Embedded Generating Unit shall remain connected is determined by linear interpolation between the following pairs of values [voltage = 20%; time = 0.625 seconds] and [voltage = 90%; time = 3 seconds].

In the case of larger and/or longer Voltage deviations, the Large VRE Embedded Generating Unit is allowed to be disconnected from the network.

4.6.6.2 In case of three phase faults on the network, at least the following performance should be achieved:

- (a) As a general rule, both during the time the fault exists in the network and during the Voltage recovery period after fault elimination, there should be no Reactive Power consumption by the Large VRE Embedded Generating Plant at the Connection Point. Reactive Power consumption is only allowed during the first 150 milliseconds after the initiation of the fault and during the 150 milliseconds immediately

after fault elimination, provided that during these periods the net consumption of Reactive Power of the Large VRE Embedded Generating Plant is not greater than 60% of the registered nominal capacity of the facility.

- (b) As a general rule, both during the time the fault exists in the network and during the Voltage recovery period after fault elimination, there should be no consumption of Active Power by the Large VRE Embedded Generating Plant. Small consumptions of Active Power are allowed during the first 150 milliseconds immediately after the initiation of the fault and during the first 150 milliseconds immediately after the fault clearing could be allowed.
- (c) Both during the fault period and during the recovery period after the fault elimination, the Large VRE Embedded Generating Plant should inject into the System the maximum possible current (I_{total}). This injection of current shall be carried out in such a way that the operation of the facility is situated inside of the shaded area of Figure 4-3, after 150 milliseconds from the initiation of the fault or the moment the fault has been eliminated.

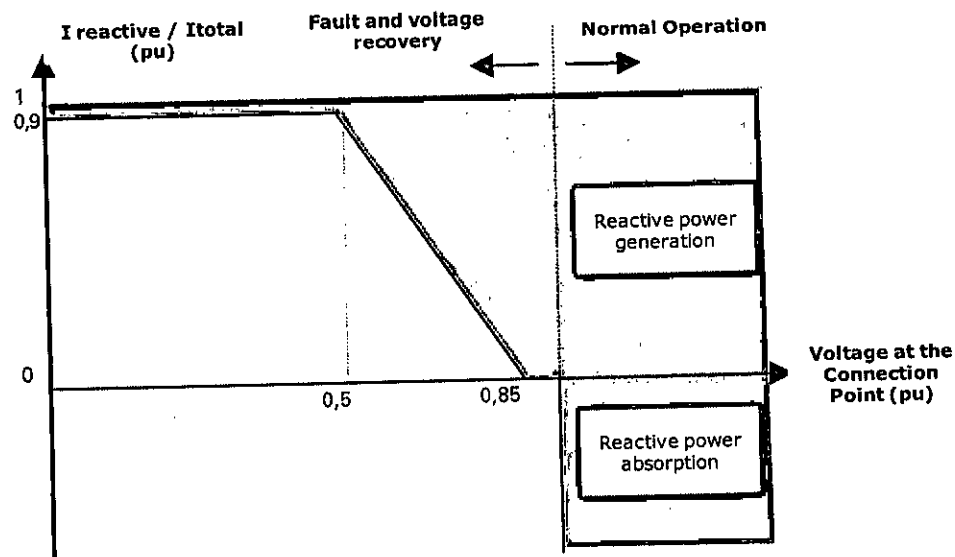


FIGURE 4-3
ALLOWED GENERATION OF REACTIVE POWER DURING VOLTAGE SAGS – LARGE VRE EMBEDDED GENERATING PLANTS

4.6.6.3 In case of unbalanced faults (single-phase faults and/or two-phase faults), at least the following performance should be achieved:

- (a) As a general rule, both during the fault period and the recovery period after fault elimination, there should be no Reactive Power consumption by the Large VRE Embedded Generating Plant at the Connection point. Small amounts of Reactive Power consumption are allowed during the first 150 milliseconds immediately after the start of fault and immediately after its elimination. In addition, transitory consumptions are allowed during the fault period, provided the following conditions are met:

- (1) Consumption of Reactive Power by the Large VRE Embedded Generating Plant shall not exceed an amount equivalent to 40% of the VRE Installed Capacity of the Large VRE Embedded Generating Plant during any 100 milliseconds period; and
 - (2) Net consumption of Reactive Power, in each cycle (16.6 milliseconds), shall not exceed 40% of VRE Installed Capacity of the Large VRE Embedded Generating Plant.
- (b) As a general rule, both during the period of existence of the fault and during the recovery period after fault elimination, there should be no consumption of Active Power by the Large VRE Embedded Generating Plant at the Connection Point. Transitory consumptions of Active Power are allowed, during the first 150 milliseconds after the initiation of the fault and the first 150 milliseconds after fault elimination, provided the following conditions are met:
- (1) Consumption of Active Power by the Large VRE Embedded Generating Plant is lower than 45% of the VRE Installed Capacity of the Large VRE Embedded Generating Plant during a period of 100 milliseconds; and
 - (2) Consumption of Active Power in each cycle (16.6 milliseconds), shall not exceed 30% of VRE Installed Capacity of the Large VRE Embedded Generating Plant.

4.6.6.4 Large VRE Embedded Generation Company shall demonstrate to the Distribution Utility that the Large VRE Embedded Generating Plant facilities installed comply with the prescriptions indicated in Subsections 4.6.6.1 to 4.6.6.4 through:

- (a) A certification issued by the Facility manufacturer, stating that its Large VRE Embedded Generating Plant has been tested and certified in a reputable laboratory showing compliance with the stated requirements. Copy of the laboratory certification shall be included to the Connection Agreement or Amended Connection Agreement.
- (b) A formal declaration from the VRE Embedded Generation Company and/or its EPC Contractor indicating that the Large VRE Embedded Generating Plant installed protection system and their settings, do not impair the performance required by Subsections 4.6.6.1 to 4.6.6.4. Copy of this declaration shall be included to the Connection Agreement or Amended Connection Agreement.

4.6.7 Protection Arrangements

4.6.7.1 The protection of Large VRE Embedded Generating Units and Equipment and their connection to the Distribution System shall be designed, coordinated, and tested to achieve the desired level of speed, sensitivity, and selectivity in fault clearing and to minimize the impact of faults on the Distribution System.

4.6.7.2 The Distribution Utility and the Large VRE Embedded Generation Company shall be solely responsible for the protection System of the electrical Equipment and facilities at their respective sides of the Connection Point.

4.6.8 Information Interchange

- 4.6.8.1 A communication system shall be established so that the System Operator, the Distribution Utility and Large VRE Embedded Generation Company can communicate with one another. During normal and emergency conditions, the System Operator through the Distribution Utility, shall communicate with the Embedded Generation Company.
- 4.6.8.2 The Large VRE Embedded Generation Company shall provide the complete RTU and communication Equipment required for the monitoring and control of the Connection Point and the Generating Units with the Distribution Utility. Large VRE Embedded Generation Companies which are registered in the WESM shall comply with the communication Equipment required under the WESM rules and the latest edition of the Philippine Grid Code, where applicable.
- 4.6.8.3 The following information shall be sent to the Distribution Utility or to the Transmission Network Provider, as appropriate:
- (a) Operation status of the Large VRE Embedded Generating Plant;
 - (b) Voltage at HV busbar of the Large VRE Embedded Generating Plant;
 - (c) Active Power, Reactive Power and electric current at HV side of step-up Transformer of the Large VRE Embedded Generating Plant;
 - (d) Status of HV Circuit Breakers and isolator switches; and
 - (e) In the case of Wind Farms, real time wind speed and wind direction measured at wind measurement mast.
- The Distribution Utility, if necessary, may furnish the above information to the System Operator.
- 4.6.8.4 Provision of additional signals may be agreed between the Distribution Utility and the Large VRE Embedded Generation Company, in which case they will be reflected in the Connection Agreement or Amended Connection Agreement.

4.7 REQUIREMENTS FOR MEDIUM EMBEDDED GENERATING PLANTS

4.7.1 Embedded Generating Unit Power Output

- 4.7.1.1 The Medium Embedded Generating Unit shall be capable of continuously supplying its Active Power output, depending on the availability of the primary resource in case of VRE generation, within the power system Frequency range of 59.7 to 60.3 Hz.
- 4.7.1.2 The Medium Embedded Generating Unit shall remain connected to the network, supplying its Active Power output and maintaining the interchange of Reactive Power at the Connection Point with Voltage Variations within $\pm 5\%$ during normal operating conditions. Outside this range and up to a Voltage Variation of $\pm 10\%$, a reduction on Active Power can be allowed, provided that the Power Factor at the Connection Point remains within the limits specified in Section 4.7.3.

4.7.2 Frequency Withstand Capability

4.7.2.1 Any variation of the power system Frequency within the range of 58.2 to 61.8 Hz should not cause the disconnection of the Medium Embedded Generating Units.

4.7.2.2 The Medium Embedded Generating Unit shall be capable to operate, for at least 5 minutes, in case of increase in Frequency within the range of 61.8 to 62.4 Hz; or decrease in Frequency within the range of 57.6 to 58.2 Hz, in both cases provided the Voltage at the Connection Point is $\pm 10\%$ of the nominal value.

4.7.2.3 The Medium Embedded Generation Company shall be responsible for protecting its Medium Embedded Generating Unit against damage from Frequency excursions outside the range of 57.6 Hz and 62.4 Hz, provided that in case the Frequency momentarily falls below 57.6 Hz the Medium Embedded Generating Unit shall remain connected for at least 5 seconds. In case of increase in Frequency above 62.4 Hz the Medium Embedded Generation Company shall disconnect the Embedded Generating Plant and/or its Embedded Generating Units from the Distribution System.

**TABLE 4-3
REQUIREMENTS FOR DIFFERENT FREQUENCY RANGES – MEDIUM
EMBEDDED GENERATING PLANTS**

Frequency		Time
Hz	p.u.	
> 62.4	> 1.04	Automatic disconnection
> 61.8 – 62.4	> 1.03 – 1.04	5 minutes
58.2 – 61.8	0.97 - 1.03	Continuous Operation
57.6 - < 58.2	0.96 - < 0.97	5 minutes
< 57.6	< 0.96	5 seconds

4.7.2.4 The Medium Embedded Generating Unit shall remain Synchronized during a rate of change of Frequency of values up to and including ± 1 Hz per second measured as a rolling average over 500 milliseconds. As Voltage dips may cause localized rate of change of Frequency values in excess of 1 Hz per second for short periods, the Large VRE Embedded Generating Unit shall remain Synchronized if the Voltage dips at the Connection Point are within the values established in Section 4.6.6.

4.7.3 Reactive Power Capability and Control

4.7.3.1 The Medium Embedded Generating Plant shall be capable of maintaining the Power Factor at its Connection Point within the range of 98% Power Factor leading to 98% Power Factor lagging, unless agreed otherwise with the Distribution Utility and reflected in the Connection Agreement or Amended Connection Agreement.

4.7.3.2 The Power Factor to be maintained at each moment will be prescribed by the Distribution Utility. In order to comply with this requirement, the Medium Embedded Generating Unit shall be equipped with an appropriate control system able to control the Reactive Power interchange over the entire operating range, which shall not create oscillations in the network.

4.7.4 Active Power Control

4.7.4.1 Medium Embedded Generating Units should be equipped with an Active Power regulation control system able to reduce the Active Power in case System Frequency exceeds 61.0 Hz. The reduction in Active Power to be achieved shall be calculated according to following formula:

$$\Delta P = 45 \cdot P_m \cdot \left(\frac{61.0 - f_n}{60} \right)$$

Where:

ΔP : is the variation in Active Power output that should be achieved

P_m : is the Active Power output before this control is activated

f_n : is the network Frequency

The reduction in Active Power output shall be performed at the maximum possible gradient, provided the technical capabilities of the Medium Embedded Generating Units are not exceeded. If the Active Power for any Medium Embedded Generating Unit is regulated downward below its Minimum Technical Load (P_{min}), shutting-down of the Medium Embedded Generating Unit is allowed.

4.7.5 Performance During Network Disturbances

4.7.5.1 The Medium Embedded Generating Unit shall be able to withstand Voltage Sag at the Connection Point without disconnection, produced by fault or disturbances in the network, which magnitude and duration profiles are within the shaded area in Figure 4-2 as indicated in Subsection 4.6.6.2.

4.7.5.2 The Medium Embedded Generation Company shall demonstrate to the Distribution Utility that the Medium Embedded Generating Plant facilities installed comply with the prescriptions indicated in Subsection 4.7.5.1 through:

- (a) A certification issued by the facility Manufacturer, stating that its Medium Embedded Generating Units have been tested and certified in a reputable laboratory showing compliance with the stated requirements. Copy of the laboratory certification shall be included to the Connection Agreement or Amended Connection Agreement.
- (b) A formal declaration from the VRE Embedded Generation Company and/or its EPC Contractor indicating that the Medium Embedded Generating Unit installed protection system and their settings, do not impair the performance indicated in Subsection 4.7.5.1. Copy of this

declaration shall be included to the Connection Agreement or Amended Connection Agreement.

4.7.6 Protection Arrangements

4.7.6.1 The protection of Medium Embedded Generating Units and Equipment and their connection to the Distribution System shall be designed, coordinated, and tested to achieve the desired level of speed, sensitivity, and selectivity in fault clearing, including anti-islanding among others, and minimize the impact of faults on the Distribution System.

4.7.6.2 Unless agreed otherwise with the Distribution Utility in the Connection Agreement, the Medium Embedded Generating Unit shall have a protection that disconnects it from the Distribution System in any Event in which part of the Distribution System, to which the Medium Embedded Generating Plant is connected become detached from the rest of the system.

4.7.6.3 The Distribution Utility and the Medium Embedded Generation Company shall be solely responsible for the protection System of the electrical Equipment and facilities at their respective sides of the Connection Point.

4.7.7 Information Interchange

4.7.7.1 The Distribution Utility will determine, based on the results of the Distribution Impact Study if a communication system between the Distribution Utility and Medium Embedded Generation Company is actually necessary in order to exchange data signals for monitoring and controlling the Distribution System during normal and emergency conditions.

4.7.7.2 If deemed appropriate, the Medium Embedded Generation Company shall provide the required communication equipment and RTU for the monitoring and control of the Connection Point and the Generating Units with the Distribution Utility.

4.7.7.3 The information that will be sent to the Distribution Utility shall be mutually agreed upon between the Distribution Utility and the Medium Embedded Generation Company and it will be reflected in the Connection Agreement or Amended Connection Agreement.

4.8 REQUIREMENTS FOR INTERMEDIATE EMBEDDED GENERATING PLANTS

4.8.1 Embedded Generating Unit Power Output

4.8.1.1 The Intermediate Embedded Generating Unit shall be capable of continuously supplying its Active Power output, depending on the availability of the primary resource in case of VRE generation, within the power system Frequency range of 59.7 to 60.3 Hz.

4.8.1.2 The Intermediate Embedded Generating Unit shall be capable of remaining connected to the network, supplying its Active Power output and maintaining the interchange of Reactive Power at the Connection Point with Voltage Variations of $\pm 5\%$ during normal operating conditions.

Outside this range and up to a Voltage Variation of $\pm 10\%$, a reduction on Active Power can be allowed, provided that the Power Factor at the Connection Point remains within the limits specified in Section 4.8.3.

4.8.2 Frequency Withstand Capability

- 4.8.2.1 Any variation of the power system Frequency within the range of 58.2 to 61.8 Hz should not cause the disconnection of the Intermediate Embedded Generating Units.
- 4.8.2.2 The Intermediate Embedded Generating Unit shall be capable to operate, for at least 5 minutes, in case of increase in Frequency within the range of 61.8 to 62.4 Hz; or decrease in Frequency within the range of 57.6 to 58.2 Hz, in both cases provided the Voltage at the Connection Point is within $\pm 10\%$ of the nominal value.
- 4.8.2.3 The Intermediate Generation Company shall be responsible for protecting its Intermediate Embedded Generating Unit against damage from Frequency excursions outside the range of 57.6 Hz and 62.4 Hz, provided that in case the Frequency momentarily falls below 57.6 Hz the Intermediate Embedded Generating Unit shall remain connected for at least 5 seconds. In case of increase in Frequency above 62.4 Hz the Intermediate Generation Company shall disconnect the Embedded Generating Plant and/or its Embedded Generating Units from the Distribution System.
- 4.8.2.4 The Intermediate Embedded Generating Unit shall remain Synchronized during a rate of change of Frequency of values up to and including ± 1 Hz per second measured as a rolling average over 500 milliseconds. As Voltage dips may cause localized rate of change of Frequency values in excess of 1 Hz per second for short periods, the Large VRE Embedded Generating Unit shall remain Synchronized if the Voltage dips at the Connection Point are within the values established in Section 4.6.6.

TABLE 4-4
REQUIREMENTS FOR DIFFERENT FREQUENCY RANGES –
INTERMEDIATE EMBEDDED GENERATING PLANTS

Frequency		Time
Hz	p.u.	
> 62.4	> 1.04	Automatic disconnection
> 61.8 – 62.4	> 1.03 – 1.04	5 minutes
58.2 – 61.8	0.97 - 1.03	Continuous Operation
57.6 - < 58.2	0.96 - < 0.97	5 minutes
< 57.6	< 0.96	5 seconds

4.8.3 Reactive Power Capability and Control

The Intermediate Embedded Generating Plant shall be capable of maintaining the Power Factor at its Connection Point within the range of 98% leading to 98% lagging, unless agreed otherwise with the Distribution Utility in the Connection Agreement or Amended Connection Agreement.

4.8.4 Active Power Control

4.8.4.1 Intermediate Embedded Generating Plants should be equipped with an Active Power regulation control system able to reduce the Active Power in case of System Frequency exceeds 61.0 Hz. The reduction in Active Power to be achieved shall be calculated according to the following formula:

$$\Delta P = 45 \cdot P_m \cdot \left(\frac{61.0 - f_n}{60} \right)$$

Where:

ΔP : is the variation in Active Power output that should be achieved

P_m : is the Active Power output before this control is activated

f_n : is the network Frequency

The reduction in Active Power output shall be performed at the maximum possible gradient, provided the technical capabilities of the Intermediate Embedded Generating Units are not exceeded. If the Active Power for any Intermediate Embedded Generating Unit is regulated downward below its Minimum Technical Load (P_{\min}), shutting-down of the Intermediate Embedded Generating Unit is allowed.

4.8.5 Performance During Network Disturbances

4.8.5.1 The Intermediate Embedded Generating Plant shall be able to withstand Voltage Sag at the Connection Point without disconnection, produced by fault or disturbances in the network, which magnitude and duration profiles are within the shaded area in Figure 4-2 as indicated in Subsection 4.6.6.2.

4.8.5.2 The Intermediate Generation Company shall demonstrate to the Distribution Utility that the Intermediate Embedded Generating Facilities installed comply with the prescriptions indicated in Subsection 4.8.5.1 through a certification issued by the facility Manufacturer, stating that its Intermediate Embedded Generating Unit has been tested and certified in a reputable laboratory showing compliance with the stated requirements. Copy of the laboratory certification shall be included to the Connection Agreement or Amended Connection Agreement.

4.8.6 Protection Arrangements

4.8.6.1 The protection of Intermediate Embedded Generating Units and Equipment and their connection to the Distribution System shall be designed, coordinated, and tested to achieve the desired level of speed, sensitivity, and selectivity in fault clearing and to minimize the impact of faults on the Distribution System.

4.8.6.2 Unless agreed otherwise with the Distribution Utility in the Connection Agreement, the Intermediate Embedded Generating Plant shall have a protection that disconnects it from the Distribution System in any Event in which part of the Distribution System, where the Intermediate

Embedded Generating Plant is connected, become detached from the rest of the system

- 4.8.6.3 The Distribution Utility and the Intermediate Embedded Generation Company shall be solely responsible for the protection System of the electrical Equipment and facilities at their respective sides of the Connection Point.

4.8.7 Information Interchange

- 4.8.7.1 The Distribution Utility will determine based on the results of the Distribution Impact Study, if a communication system between the Distribution Utility and the Intermediate Embedded Generation Company is actually necessary in order to exchange data signals for monitoring and controlling the Distribution System during normal and emergency conditions.
- 4.8.7.2 If deemed appropriate, the Intermediate Embedded Generation Company shall provide the required communication Equipment and RTU for the monitoring and control of the Connection Point and the Generating Units with the Distribution Utility.
- 4.8.7.3 The information that will be sent to the Distribution Utility shall be mutually agreed upon between the Distribution Utility and the Intermediate Embedded Generation Company and it will be reflected in the Connection Agreement or Amended Connection Agreement.

4.9 REQUIREMENTS FOR SMALL AND MICRO EMBEDDED GENERATING PLANTS

4.9.1 Embedded Generating Unit Power Output

- 4.9.1.1 The Small or Micro Embedded Generating Unit shall be capable of continuously supplying its Active Power output, depending on the availability of the primary resource in case of VRE generation, within the power system Frequency range of 59.7 to 60.3 Hz.
- 4.9.1.2 The Small or Micro Embedded Generating Unit shall remain connected to the network with Voltage Variations within the range $\pm 10\%$ during normal operating conditions.

4.9.2 Frequency Withstand Capability

Any variation of the power system Frequency within the range of 58.2 to 61.8 Hz should not cause the disconnection of the Small or Micro Embedded Generating Units.

4.9.3 Reactive Power Capability and Control

The Small or Micro Embedded Generating Plant shall be capable of maintaining the Power Factor of not less than 85% lagging at its Connection Point, unless agreed otherwise with the Distribution Utility in the Connection Agreement or Amended Connection Agreement.

4.9.4 Performance During Network Disturbances

The Small or Micro Embedded Generating Plant shall be able to withstand Voltage Sag or Overvoltages at the Connection Point without disconnection, produced by fault or disturbances in the network, which magnitude and duration profiles are within the following limits:

TABLE 4-5
MINIMUM TIME REQUIREMENTS FOR SMALL AND MICRO
EMBEDDED GENERATING PLANTS TO REMAIN CONNECTED AT
DIFFERENT VOLTAGE RATINGS

Voltage Range (% of Base Voltage)	Time
$V < 50$	0.16
$50 \leq V < 90$	2.00
$90 \leq V \leq 110$	Normal Operating Range
$110 < V < 120$	1.00
$V \geq 120$	0.16

4.9.5 Protection Arrangements

4.9.5.1 The Distribution Utility and the Small or Micro Embedded Generation Company shall be solely responsible for the protection System of the electrical Equipment and facilities at their respective sides of the Connection Point.

4.9.5.2 The Small or Micro Embedded Generation Company shall be responsible for providing adequate protection for its facility under any operating conditions, whether or not the Embedded Generating Plant is in operation. Conditions include, but are not limited to, single phasing of supply, system faults, Equipment failures, abnormal Voltage or Frequency, lightning and switching surges, excessive harmonic Voltages, excessive negative sequence Voltage and islanding.

4.9.5.3 The Small or Micro Embedded Generation Company shall provide synchronizing devices for synchronizing the facility with the Distribution System. Automatic synchronization devices shall be installed to monitor and control the synchronism. The Distribution Utility shall review, approve and inspect the method of synchronization. Automatic synchronizing settings shall not be changed following installation unless agreed with the Distribution Utility. Typical limits for synchronizing parameters are given in Table 4-6.

TABLE 4-6
TYPICAL SYNCHRONIZING PARAMETERS LIMITS

Maximum Frequency Difference Δf [Hz]	Maximum Voltage Difference ΔV [%]	Maximum Phase Angle Difference $\Delta\Phi$ [Degrees]
0.3	10	20

4.9.5.4 To prevent islanding, in which Small or Micro Embedded Generating Units energizes a portion of the Distribution System through the Connection Point, the Small or Micro Embedded Generating Plant shall detect islanding and disconnect from the Distribution System within 2 seconds from the formation of the island. The User using Small or Micro Embedded Generating Plant shall provide facilities against islanding to isolate and block the facility from closing back into the Distribution System until the system is energized for at least 10 minutes from the normal utility source.

4.9.5.5 The Grounding scheme of the Small or Micro Embedded Generating Unit shall not cause Overvoltage that exceed the rating of the Equipment connected to the Distribution System and shall not disrupt the coordination of the ground fault protection on the Distribution System. All electrical systems and Equipment shall be grounded in accordance with the requirements of the PEC.

4.9.5.6 The protection of Small or Micro Embedded Generating Units and Equipment and their connection to the Distribution System shall be designed, coordinated, and tested to achieve the desired level of speed, sensitivity, and selectivity in fault clearing and to minimize the impact of faults on the Distribution System.

4.9.5.7 The Small or Micro Embedded Generation Company shall submit the proposed fused types and/or relay settings to the Distribution Utility for review and acceptance. Any subsequent relay or fuse change shall also be submitted to the Distribution Utility for acceptance.

4.9.5.8 The Small or Micro Embedded Generation Company shall provide a visible disconnecting device for use by the Distribution Utility to electrically isolate the Distribution System from the Small or Micro Embedded Generating Plant and to establish working clearances for maintenance, safety and system considerations. The disconnecting device shall be physically located for ease of access by the Distribution Utility personnel located within 10 feet from the Connection Point. If this is not practical the disconnecting device shall be located between the Small or Micro Embedded Generating facility and the Connection Point. The type of disconnecting device must allow for visual indication of the contact position with a padlock. It shall be readily accessible at all times by the Distribution Utility personnel.

Labels, markings and warning signs shall be applied near the Connection Point to alert the Distribution Utility personnel of a generating facility installed within the generating plant premises.

4.9.5.9 Protective relays shall be installed to trip the corresponding Circuit Breaker during abnormal conditions. Protective relays for a given Small or Micro Embedded Generating Plant are shown in Tables 4-7, 4-8 and 4-9.

TABLE 4-7
INTERCONNECTION PROTECTIVE FUNCTION REQUIREMENTS FOR INDUCTION GENERATING PLANTS

Device	Protective Equipment	Generating Unit Size	
		≤ 10 kW	> 10 kW
27	Under Voltage Relay	X	X
27 Gen	Voltage Check Relay	X	X
59	Overvoltage Relay		X
81/O – 81/U	Over-Under Frequency Relay		X
	Anti-Islanding Relay (phase shift or RoCoF)	X	X

TABLE 4-8
INTERCONNECTION PROTECTIVE FUNCTION REQUIREMENTS FOR SYNCHRONOUS GENERATING PLANTS

Device	Protective Equipment	Generating Unit Size	
		≤ 10 kW	> 10 kW
25	Synchronism-Check Relay	X	X
27	Under Voltage Relay	X	X
51V	Over current Relay – Voltage Restrained		X
59	Overvoltage Relay		X
81/O – 81/U	Over-Under Frequency Relay		X
	Anti-Islanding Relay (phase shift or RoCoF)	X	X

TABLE 4-9
INTERCONNECTION PROTECTIVE FUNCTION REQUIREMENTS FOR INVERTERS

Device	Protective Equipment	Generating Unit Size	
		≤ 10 kW	> 10 kW
27	Under Voltage Relay	X	X
59	Overvoltage Relay	X	X
81/O – 81/U	Over-Under Frequency Relay	X	X
	Anti-Islanding Relay (phase shift or RoCoF)	X	X

4.9.5.10 The Small or Micro Embedded Generating Plant should immediately disconnect from the Distribution System when the System is down. For a Distribution System with automatic reclosing, the Small or Micro

Embedded Generating Plant should wait for 10 minutes until the recloser has normalized the portion of the system to which the Small or Micro Embedded Generating Plant is connected before synchronizing back to the system.

4.10 REQUIREMENTS FOR DISTRIBUTION USERS

4.10.1 Requirements Relating to the Connection Point

- 4.10.1.1 The User's Equipment shall be connected to the Distribution System at a Voltage level agreed to by the Distribution Utility and the User based on the Distribution Impact Studies.
- 4.10.1.2 For a connection at Low Voltage, the Connection Point shall, in general, be at the User's Load side terminal of the Metering Equipment.
- 4.10.1.3 For a connection at MV and HV, the Connection Point arrangements shall be agreed upon by the Distribution Utility and the User.
- 4.10.1.4 The Connection Point shall be controlled by a Circuit Breaker that is capable of interrupting the maximum short circuit current at the point of connection.
- 4.10.1.5 Disconnect switches, or other isolating means, shall also be provided and arranged to isolate the Circuit Breaker for maintenance purposes.

4.10.2 Protection Arrangements

- 4.10.2.1 The protection of the User's Equipment at the Connection Point shall be designed, coordinated, and tested to achieve the desired level of speed, sensitivity, and selectivity in fault clearing and to minimize the impact of faults on the Distribution System.
- 4.10.2.2 The Distribution Utility and the User shall be solely responsible for the protection System of electrical Equipment and facilities at their respective sides of the Connection Point. The Distribution Utility, upon request of the User, shall provide the technical data at the Connection Point necessary for the User to design its protection system.
- 4.10.2.3 The Distribution Utility may require specific Users to provide other Protection schemes, designed and developed to minimize the risk and/or impact of disturbances on the Distribution System.

4.10.3 Transformer Connection and Grounding

The Distribution Utility shall specify the connection and Grounding requirements for the Transformer, in accordance with the provisions of Section 4.2.11.

4.10.4 Underfrequency Relays for Automatic Load Dropping

- 4.10.4.1 The Connection Agreement or Amended Connection Agreement shall specify the manner in which Demand, subject to Automatic Load Dropping, will be split into discrete MW blocks to be actuated by Underfrequency Relays.
- 4.10.4.2 The Underfrequency Relays to be used in Automatic Load Dropping shall be fully digital with the following characteristics:

- (a) Frequency setting range: 57 to 62 Hz in steps of 0.1 Hz, preferably 0.05 Hz;
- (b) Adjustable time delay: 0 to 60 seconds in steps of 0.1 second;
- (c) Rate of Frequency setting range: 0 to ± 10 Hz per second in steps of 0.1 Hz per second;
- (d) Operating time delay: less than 0.1 second;
- (e) Voltage lock-out: Selectable within 55% to 90% of nominal Voltage;
- (f) Facility stages: Minimum of two stages operation; and
- (g) Output contacts: Minimum of three output contacts per stage.

4.10.4.3 The Underfrequency Relays shall be suitable for operation from a nominal AC input of 115 volts. The Voltage supply to the Underfrequency Relays shall be sourced from the primary System at the supply point to ensure that the input Frequency to the Underfrequency Relay is the same as that of the primary System.

4.10.4.4 The tripping facility shall be designed and coordinated in accordance with the following reliability considerations:

- (a) Dependability: Failure to trip at any one particular Demand shedding point shall not harm the overall operation of the scheme. The overall dependability of the scheme shall not be lower than 96%; and
- (b) Outages: The amount of Demand under control shall not be reduced significantly during the Outage or maintenance of the Equipment.

4.11 FIXED ASSET BOUNDARY DOCUMENT REQUIREMENTS

4.11.1 Fixed Asset Boundary Document

4.11.1.1 The Fixed Asset Boundary Documents for any Connection Point shall provide the information and specify the operational responsibilities of the Distribution Utility and the User for the following:

- (a) MV/HV Equipment;
- (b) LV Equipment; and
- (c) Communications and Metering Equipment.

4.11.1.2 For the Fixed Asset Boundary Document referred to in item (a) above, the responsible management unit shall be shown, in addition to the Distribution Utility or the User. In the case of Fixed Asset Boundary Documents referred to in items (b) and (c) above, with the exception of protection Equipment and inter-trip Equipment operation, it will be sufficient to indicate the responsible User or the Distribution Utility.

4.11.1.3 The Fixed Asset Boundary Document shall show precisely the Connection Point and shall specify the following:

- (a) Equipment and their ownership;
- (b) Accountable Persons;
- (c) Safety Rules and procedures including Local Safety Instructions and the Safety Coordinator(s) or any other persons responsible for safety;
- (d) Operational procedures and the responsible party for operation and control;

- (e) Maintenance requirements and the responsible party for undertaking maintenance; and
- (f) Any agreement pertaining to emergency conditions.

4.11.1.4 The Fixed Asset Boundary Documents shall be available at all times for the use of the operations personnel of the Distribution Utility and the User.

4.11.2 Accountable Persons

- 4.11.2.1 Prior to the Completion Date specified in the Connection Agreement or Amended Connection Agreement, the User shall submit to the Distribution Utility a list of Accountable Persons who are duly authorized to sign the Fixed Asset Boundary Documents on behalf of the User.
- 4.11.2.2 Prior to the Completion Date specified in the Connection Agreement or Amended Connection Agreement, the Distribution Utility shall provide the User the name of the Accountable Person who shall sign the Fixed Asset Boundary Documents on behalf of the Distribution Utility.
- 4.11.2.3 Any change to the list of Accountable Persons shall be communicated to the other party at least 6 weeks before the change becomes effective. If the change was not anticipated, it must be communicated as soon as possible to the other party, with an explanation why the change had to be made.
- 4.11.2.4 Unless specified otherwise in the Connection Agreement or the Amended Connection Agreement, the construction, Test and Commissioning, control, operation and maintenance of Equipment, accountability, and responsibility shall follow ownership.

4.11.3 Preparation of Fixed Asset Boundary Document

- 4.11.3.1 The Distribution Utility shall establish the procedure and forms required for the preparation of the Fixed Asset Boundary Documents.
- 4.11.3.2 The User shall provide the information that will enable the Distribution Utility to prepare the Fixed Asset Boundary Document, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.
- 4.11.3.3 The Distribution Utility shall prepare the Fixed Asset Boundary Documents for the Connection Point at least 2 weeks prior to the Completion Date.
- 4.11.3.4 The Fixed Asset Boundary Document for the Equipment at the Connection Point shall include the details of the lines or cables emanating from the Distribution Utility's and the User's sides of the Connection Point.
- 4.11.3.5 The date of issue and the issue number shall be included in every page of the Fixed Asset Boundary Document.

4.11.4 Signing and Distribution of Fixed Asset Boundary Document

- 4.11.4.1 Prior to the signing of the Fixed Asset Boundary Document, the Distribution Utility shall send a copy of the completed Fixed Asset

Boundary Document to the User, for any revision or for confirmation of its accuracy.

4.11.4.2 The Accountable Persons designated by the Distribution Utility and the User shall sign the Fixed Asset Boundary Document, after confirming its accuracy.

4.11.4.3 Once signed but not less than 2 weeks before the implementation date, the Distribution Utility shall provide two copies of the Fixed Asset Boundary Document to the User, with a notice indicating the date of issue, the issue number and the implementation date of the Fixed Asset Boundary Document.

4.11.5 Modifications to an Existing Fixed Asset Boundary Document

4.11.5.1 When a User has determined that a Fixed Asset Boundary Document requires modification, it shall inform the Distribution Utility at least 8 weeks before implementing the modification. The Distribution Utility shall then prepare a revised Fixed Asset Boundary Document at least 6 weeks before the implementation date of the modification.

4.11.5.2 When the Distribution Utility has determined that a Fixed Asset Boundary Document requires modification, it shall prepare a revised Fixed Asset Boundary Document at least 6 weeks prior to the implementation date of the modification.

4.11.5.3 If the Distribution Utility or a User has determined that the Fixed Asset Boundary Document requires modification to reflect an emergency condition, the Distribution Utility or the User, as the case may be, shall immediately notify the other party. The Distribution Utility and the User shall meet to discuss the required modification to the Fixed Asset Boundary Document, and shall decide whether the change is temporary or permanent in nature. Within 7 days after the conclusion of the meeting between the Distribution Utility and the User, the Distribution Utility shall provide the User a revised Fixed Asset Boundary Document.

4.11.5.4 The procedure specified in Section 4.11.4 shall be applied to the revised Fixed Asset Boundary Document. The Distribution Utility's notice shall indicate the revision, the new issue number, and the new date of issue.

4.12 ELECTRICAL DIAGRAM REQUIREMENTS

4.12.1 Responsibilities of the Distribution Utility and Users

4.12.1.1 The Distribution Utility shall specify the procedure and format to be followed in the preparation of the Electrical Diagrams for any Connection Point.

4.12.1.2 The User shall prepare and submit to the Distribution Utility an Electrical Diagram for all the Equipment on the User's side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

4.12.1.3 The Distribution Utility shall provide the User with an Electrical Diagram for all the Equipment on the Distribution Utility's side of the

Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

- 4.12.1.4 If the Connection Point is at the User's Site, the User shall prepare and distribute a composite Electrical Diagram for the entire Connection Point. Otherwise, the Distribution Utility shall prepare and distribute the composite Electrical Diagram for the entire Connection Point.

4.12.2 Preparation of Electrical Diagrams

- 4.12.2.1 The Electrical Diagrams shall provide an accurate record of the layout and circuit connections, ratings and identification of Equipment, and related apparatus and devices at the Connection Point.
- 4.12.2.2 If possible, all the Equipment at the Connection Point shall be shown in one Electrical Diagram. When more than one Electrical Diagram is necessary, duplication of identical information shall be minimized. The Electrical Diagrams shall represent, as closely as possible, the physical arrangement of the Equipment and their electrical connections.
- 4.12.2.3 The Electrical Diagrams shall be prepared using the Site and Equipment Identification prescribed in Article 6.12. The current status of the Equipment shall be indicated in the diagram. For example, a decommissioned switch bay shall be labeled "Spare Bay."
- 4.12.2.4 The title block of the Electrical Diagram shall include the names of authorized persons together with provisions for the details of revisions, dates, and signatures.

4.12.3 Changes to Electrical Diagrams

- 4.12.3.1 If the Distribution Utility or a User decides to add new Equipment or change an existing Equipment Identification, the Distribution Utility or the User, as the case may be, shall provide the other party a revised Electrical Diagram, at least 1 month prior to the proposed addition or change.
- 4.12.3.2 If the modification involves the replacement of existing Equipment, the revised Electrical Diagram shall be provided to the other party in accordance with the schedule specified in the Amended Connection Agreement.
- 4.12.3.3 The revised Electrical Diagram shall incorporate the new Equipment to be added, the existing Equipment to be replaced or the change in Equipment Identification.

4.12.4 Validity of Electrical Diagrams

- 4.12.4.1 The composite Electrical Diagram prepared by the Distribution Utility or the User, in accordance with the provisions of Section 4.12.1, shall be the Electrical Diagram to be used for all operational and planning activities associated with the Connection Point.
- 4.12.4.2 If a dispute involving the accuracy of the composite Electrical Diagram arises, a meeting between the Distribution Utility and the User shall be held as soon as possible, to resolve the dispute.

4.13 CONNECTION POINT DRAWING REQUIREMENTS

4.13.1 Responsibilities of the Distribution Utility and Users

- 4.13.1.1 The Distribution Utility shall specify the procedure and format to be followed in the preparation of the Connection Point Drawing for any Connection Point.
- 4.13.1.2 The User shall prepare and submit to the Distribution Utility the Connection Point Drawing for the User's side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.
- 4.13.1.3 The Distribution Utility shall provide the User with the Connection Point Drawing for the Distribution Utility's side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.
- 4.13.1.4 If the Connection Point is at the User Site, the User shall prepare and distribute a composite Connection Point Drawing for the entire Connection Point. Otherwise, the Distribution Utility shall prepare and distribute the composite Connection Point Drawing for the entire Connection Point.

4.13.2 Preparation of Connection Point Drawings

- 4.13.2.1 The Connection Point Drawing shall provide an accurate record of the layout and circuit connections, ratings and identification of Equipment, and related apparatus and devices at the Connection Point.
- 4.13.2.2 The Connection Point Drawing shall indicate the Equipment layout, common protection, and control and auxiliaries. The Connection Point Drawing shall represent, as closely as possible, the physical arrangement of the Equipment and their electrical connections.
- 4.13.2.3 The Connection Point Drawing shall be prepared using the Site and Equipment Identification prescribed in Article 6.12. The current status of the Equipment shall be indicated in the drawing. For example, a decommissioned switch bay shall be labeled "Spare Bay."
- 4.13.2.4 The title block of the Connection Point Drawing shall include the names of authorized persons together with provision for the details of revisions, dates, and signatures.

4.13.3 Changes to Connection Point Drawings

- 4.13.3.1 If the Distribution Utility or a User decides to add new Equipment or change an existing Equipment Identification, the Distribution Utility or the User, as the case may be, shall provide the other party a revised Connection Point Drawing, at least 1 month prior to the proposed addition or change.
- 4.13.3.2 If the modification involves the replacement of existing Equipment, the revised Connection Point Drawing shall be provided to the other party in accordance with the schedule specified in the Amended Connection Agreement.

4.13.3.3 The revised Connection Point Drawing shall incorporate the new Equipment to be added, the existing Equipment to be replaced, or the change in Equipment Identification.

4.13.3.4 The Distribution Utility and the User shall, if they have agreed to do so in writing, modify their respective copies of the Connection Point Drawings to reflect the change that they have agreed on, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

4.13.4 Validity of the Connection Point Drawings

4.13.4.1 The composite Connection Point Drawing prepared by the Distribution Utility or the User, in accordance with Section 4.13.1, shall be the Connection Point Drawing to be used for all operational and planning activities associated with the Connection Point.

4.13.4.2 If a dispute arises involving the accuracy of the composite Connection Point Drawing, a meeting between the Distribution Utility and the User shall be held as soon as possible, to resolve the dispute.

4.14 DISTRIBUTION DATA REGISTRATION

4.14.1 Data to be Registered

4.14.1.1 The data relating to the Connection Point and the User Development that are submitted by the User to the Distribution Utility shall be registered according to the following data categories:

- (a) Forecast Data;
- (b) Estimated Equipment Data; and
- (c) Registered Equipment Data.

4.14.1.2 The Forecast Data, including Demand and Active Energy, shall contain the User's best estimate of the data being projected for the five succeeding years.

4.14.1.3 The Estimated Equipment Data shall contain the User's best estimate of the values of parameters and information about the Equipment for the five succeeding years.

4.14.1.4 The Registered Equipment Data shall contain validated actual values of parameters and information about the Equipment that are submitted by the User to the Distribution Utility at the connection date. The Registered Equipment Data shall include the Connected Project Planning Data, which shall replace any estimated values of parameters and information about the Equipment previously submitted as Preliminary Project Planning Data and Committed Project Planning Data.

4.14.2 Stages of Data Registration

4.14.2.1 The data relating to the Connection Point and the User Development that are submitted by a User applying for a Connection Agreement or an Amended Connection Agreement shall be registered in three stages and classified accordingly as:

- (a) Preliminary Project Planning Data;

- (b) Committed Project Planning Data; and
- (c) Connected Project Planning Data;

4.14.2.2 The data that are submitted at the time of application for a Connection Agreement or an Amended Connection Agreement shall be considered as Preliminary Project Planning Data. These data shall contain the Standard Planning Data specified in Article 5.4, and the Detailed Planning Data specified in Article 5.5, when required ahead of the schedule specified in the Connection Agreement or Amended Connection Agreement.

4.14.2.3 Once the Connection Agreement or the Amended Connection Agreement is signed, the Preliminary Project Planning Data shall become the Committed Project Planning Data, which shall be used in evaluating other applications for Distribution System connection or modification of existing Distribution System connections and in preparing the Distribution Development Plan.

4.14.2.4 The Estimated Equipment Data shall be updated, confirmed, and replaced with validated actual values of parameters and information about the Equipment at the time of connection, which shall become the Connected Project Planning Data. These data shall be registered in accordance with the categories specified in Section 4.14.1 and shall be used in evaluating other applications for Distribution System connection or modification of existing Distribution System connections and in preparing the Distribution Development Plan.

4.14.3 Data Forms

The Distribution Utility shall develop the forms for all data to be submitted in accordance with an application for a Connection Agreement or an Amended Connection Agreement.

CHAPTER 5

DISTRIBUTION PLANNING

5.1 PURPOSE

- (a) To specify the responsibilities of the Distribution Utilities and the Users of the Distribution System in planning the development of the Distribution System;
- (b) To specify the technical studies and planning procedures that will ensure the safety and Reliability of the Distribution System;
- (c) To specify the planning data required for a User seeking a new connection or a modification of an existing connection to the Distribution System; and
- (d) To specify the data requirements to be used by the Distribution Utilities in planning the development of the Distribution System.

5.2 DISTRIBUTION PLANNING RESPONSIBILITIES AND PROCEDURES

5.2.1 Distribution Planning Responsibilities

5.2.1.1 The Distribution Utility shall be responsible for Distribution Planning, including:

- (a) Analyzing the impact of the connection of new facilities such as Embedded Generating Plants, Loads, distribution lines, or substations;
- (b) Planning the expansion of the Distribution System to ensure its adequacy to meet forecasted Demand and the connection of new Embedded Generating Plants; and
- (c) Identifying and correcting problems on Power Quality, System Loss, and Reliability in the Distribution System.

5.2.1.2 The Users of the Distribution System, including Embedded Generation Companies, Large Customers, and other entities that have a System connected to the Distribution System shall cooperate with the Distribution Utility in maintaining a Distribution Planning data.

5.2.2 Submission of Planning Data

5.2.2.1 As required by the Distribution Utility, a User applying for connection or a modification of an existing connection to the Distribution System shall submit to the Distribution Utility the relevant Standard Planning Data specified in Article 5.4 and the Detailed Planning Data specified in Article 5.5, in accordance with the requirements prescribed in Article 4.3.

5.2.2.2 As required by the Distribution Utility, a User shall submit annually to the Distribution Utility the relevant historical planning data for the previous year and the forecast planning data for the five succeeding years by calendar week 23 of the current year. These shall include the updated Standard Planning Data and the Detailed Planning Data.

- 5.2.2.3 The required Standard Planning Data specified in Article 5.4 shall consist of information necessary for the Distribution Utility to evaluate the impact of any User Development on the Distribution System.
- 5.2.2.4 The Detailed Planning Data specified in Article 5.5 shall include additional information necessary for the conduct of a more accurate Distribution Planning study. This shall cover circuit parameters, switchgear, and protection arrangements of equipment directly connected to or affecting the Distribution System. The data shall be adequate to enable the Distribution Utility to assess any implication associated with the Connection Points.
- 5.2.2.5 The Standard Planning Data and Detailed Planning Data shall be submitted by the User to the Distribution Utility according to the following categories:
- (a) Forecast Data;
 - (b) Estimated Equipment Data; and
 - (c) Registered Equipment Data.
- 5.2.2.6 The Forecast Data shall contain the User's best estimate of the data, including Energy and Demand, being projected for the five succeeding years.
- 5.2.2.7 The Estimated Equipment Data shall contain the User's best estimate of the values of parameters and information pertaining to its Equipment.
- 5.2.2.8 The Registered Equipment Data shall contain validated actual values of parameters and information about the User's Equipment, which are part of the Connected Project Planning Data submitted by the User to the Distribution Utility at the time of connection.

5.2.3 Consolidation and Maintenance of Planning Data

- 5.2.3.1 The Distribution Utility shall consolidate and maintain the Distribution planning data according to the following categories:
- (a) Forecast Data;
 - (b) Estimated Equipment Data; and
 - (c) Registered Equipment Data.
- 5.2.3.2 If there is any change to its planning data, the User shall notify the Distribution Utility of the change as soon as possible. The notification shall contain the time and date when the change took effect, or is expected to take effect, as the case may be. If the change is temporary, the time and date when the data is expected to revert to its previous registered value shall also be indicated in the notification.

5.2.4 Evaluation of Proposed Development

- 5.2.4.1 The Distribution Utility shall conduct Distribution Impact Studies to assess the effect of the proposed User Development on the Distribution System and the System of other Users.
- 5.2.4.2 The Distribution Utility shall notify the User of the results of the Distribution Impact Studies.

5.2.4.3 The Distribution Utility shall also notify the User of any planned development in the Distribution System that may have an impact on the User System.

5.2.5 Preparation of Distribution Development Plan

5.2.5.1 The Distribution Utility shall collate and process the planning data submitted by the Users into a cohesive forecast and use this in preparing the data for the Distribution Development Plan (DDP).

5.2.5.2 The Distribution Utility shall develop and submit annually to the DOE a DDP. In the case of an Electric Cooperative, such plan shall be submitted to the DOE through the NEA. A copy of the DDP shall also be submitted to the ERC, through the DMC.

5.2.5.3 The Distribution Development Plan shall include:

- (a) Energy and Demand forecasts;
- (b) Sub-transmission capacity expansion;
- (c) Distribution substation siting and sizing;
- (d) Distribution feeder routing and sizing;
- (e) Distribution Reactive Power compensation plan;
- (f) Other Distribution reinforcement plans; and
- (g) A summary of the technical and economic analysis performed to justify the DDP.

5.2.5.4 If a User believes that the cohesive forecast prepared by the Distribution Utility does not accurately reflect its assumptions on the planning data, it shall promptly notify the Distribution Utility of its concern. The Distribution Utility and the User shall promptly meet to address the concern of the User.

5.3 DISTRIBUTION PLANNING STUDIES

5.3.1 Distribution Planning Studies

5.3.1.1 The Distribution Utility shall conduct distribution planning studies to ensure the safety and reliability of the Distribution System for the following purposes:

- (a) Preparation of the Distribution Development Plan to be submitted annually to DOE;
- (b) Evaluation of Distribution System reinforcement projects; and
- (c) Evaluation of any proposed User Development, which is submitted in accordance with an application for a Connection Agreement or an Amended Connection Agreement.

5.3.1.2 The distribution planning studies shall be conducted to assess the impact on the Distribution System, or to any User System of any Demand Forecast or any proposed Equipment change in the Distribution System, or the User System and to identify corrective measures to eliminate the deficiencies in the Distribution System, or the User System.

5.3.1.3 The relevant technical studies described in Sections 5.3.2 to 5.3.5 and the required planning data specified in Articles 5.4 and 5.5 shall be used in the conduct of the distribution planning studies.

5.3.1.4 The Distribution Utility shall conduct distribution planning analysis which shall include:

- (a) The determination of optimum patterns for the selection of sites and sizes of distribution substations;
- (b) The determination of optimum patterns for feeder development;
- (c) The development of optimum Reactive Power compensation programs; and
- (d) The development of an optimum feeder configuration and switching controls for distribution feeders.

5.3.1.5 The distribution planning studies shall be performed using lifecycle costing methods. The cost of capital and the discount rate used in such analysis shall be prescribed by the ERC.

5.3.2 Voltage Drop Studies

5.3.2.1 Voltage drop studies shall be performed to determine the Voltages at the Connection Points for the forecasted Demand of the existing Distribution System and any planned expansion, reinforcement, or development.

5.3.2.2 Voltage drop studies shall be performed to evaluate the impact of the connection of new Embedded Generating Plants, loads, or distribution lines on the Distribution System.

5.3.3 Short Circuit Studies

5.3.3.1 Short circuit studies shall be performed to evaluate the effect on the Distribution System Equipment of the connection of new Generating Plants and other facilities that will result in increased fault duties for the Distribution System Equipment. These studies shall identify the Equipment that could be damaged when current exceeds the design limit of the Equipment. The studies shall also identify the Circuit Breakers and fuses, which may fail when interrupting possible short circuit currents.

5.3.3.2 Three-phase short-circuit studies shall be performed for all nodes of the Distribution System for the maximum and minimum generation scenarios of the Grid and for different system circuit configurations.

5.3.3.3 Single line-to-ground fault studies shall also be performed for critical Distribution System nodes. These studies shall identify the most severe conditions that the Distribution System Equipment may be exposed to.

5.3.3.4 The Distribution Utility and the User shall exchange information on fault infeed levels at the Connection Point. The information shall include:

- (a) The maximum and minimum three-phase and line-to-ground fault infeeds;
- (b) The X/R ratio under short circuit conditions; and
- (c) In the case of interconnected Systems, an adequate equivalent network representation for short circuit calculations.

5.3.3.5 Alternative Distribution System circuit configurations may be studied to reduce the short circuit current within the limits of existing Equipment. The results shall be considered satisfactory when the short-circuit currents are within the design limits of the Equipment and the proposed Distribution System configurations are suitable for flexible and safe operation.

5.3.4 System Loss Studies

5.3.4.1 System Loss studies shall be performed to identify, classify, and quantify the losses in the Distribution System. The various categories and components of System Loss specified in Article 3.4 shall be identified and quantified in conducting the System Loss studies.

5.3.4.2 System Loss studies shall be performed to determine the effects of any User Development and any development in the Distribution System on the efficiency of the Distribution System.

5.3.5 Distribution Reliability Studies

5.3.5.1 Distribution Reliability studies shall be performed to determine the frequency and duration of Customer Interruptions in the Distribution System.

5.3.5.2 The historical Reliability performance of the Distribution System shall be determined from the Interruptions data of the Distribution System.

5.4 STANDARD PLANNING DATA

5.4.1 Energy and Demand Forecast

5.4.1.1 The User shall provide the Distribution Utility with its Energy and Demand forecasts at each Connection Point for the five succeeding years.

5.4.1.2 The Forecast Data for the first year shall include monthly Energy and Demand forecasts, while the remaining four years shall include only the annual Energy and Demand forecasts.

5.4.1.3 The Users shall provide the net values of Energy and Demand forecast after any deductions to reflect the output of a Customer Self-Generating Plant. Such deductions shall be stated separately in the Forecast Data.

5.4.1.4 The following factors shall be taken into account by the Distribution Utility and the User when forecasting Demand:

- (a) Historical Demand data;
- (b) Demand trends;
- (c) Significant public events;
- (d) Customer Self-Generating Plant schedules;
- (e) Demand transfers;
- (f) Interconnection with adjacent Distribution Utilities; and
- (g) Other relevant factors.

5.4.1.5 The Large Conventional, Large VRE, Medium, Intermediate Embedded Generation Companies and, if required, End-Users using Small Embedded Generating Plants shall submit to the Distribution Utility the

projected capability to be generated on an hourly basis by each Generating Unit or Generating Plant.

5.4.2 Embedded Generating Unit Data

5.4.2.1 The Embedded Generation Company shall provide the Distribution Utility with data relating to the Embedded Generating Units.

5.4.2.2 The Embedded Generation Company shall provide the Distribution Utility the following information about its Generating Unit or Generating Plant:

- (a) Rated Capacity (MVA and MW);
- (b) Rated Voltage (kV);
- (c) Type of Generating Unit and expected running mode(s);
- (d) Direct axis subtransient reactance (%); and
- (e) Rated capacity, voltage, and impedance of the Generating Unit's step-up Transformer.

5.4.2.3 The following information shall be provided by the Embedded Generation Company for their Wind Generating Plant:

- (a) Name and location of the Wind Farm;
- (b) Wind Farm capacity;
- (c) Total VRE Installed Capacity;
- (d) Number of units and unit size;
- (e) Type of wind turbines used in the Wind Farm (fixed speed/variable speed);
- (f) Wind turbine Manufacturer;
- (g) Rated power of each wind turbine (kW);
- (h) Rated Apparent Power (kVA);
- (i) Rated Frequency (Hz);
- (j) Rated wind speed (m/s);
- (k) Cut-in wind speed (m/s);
- (l) Cut-off wind speed (m/s); and
- (m) Rated Voltage (V).

5.4.2.4 The following information shall be provided by the Embedded Generation Company for their PVSs:

- (a) Name and location of the PVS Generating Unit;
- (b) Total Installed Capacity (kWp);
- (c) Number of units and unit size;
- (d) Inverter Power Rating (kW);
- (e) Inverter Manufacturer and Model;
- (f) Solar Panel Technology;
- (g) PVS Transformer data, if applicable;
- (h) Transformer Voltage Ratio, if applicable;
- (i) Percentage Impedance, if applicable;
- (j) Winding Connection, if applicable; and

(k) Tap Settings, if applicable.

5.4.2.5 If the Embedded Generating Unit is connected to the Distribution System at a Connection Point with a bus arrangement which is, or may be operated in separate sections, the bus section to which each Generating Unit is connected shall be identified.

5.4.3 User System Data

5.4.3.1 If the User is to be connected at LV, the following data shall be provided to the Distribution Utility:

- (a) Connected Loads; and
- (b) Maximum Demand.

5.4.3.2 If the User is to be connected at MV or HV, the following data shall be provided to the Distribution Utility:

- (a) All types of Loads:
 - (1) Connected Load, including type and control arrangements;
 - (2) Maximum Demand;
- (b) Fluctuating and Cyclical Loads:
 - (1) The rate of change of the Demand;
 - (2) The switching interval; and
 - (3) The magnitude of the largest step change.

5.4.3.3 The User shall provide the Electrical Diagrams and Connection Point Drawings of the User System and the Connection Point, as specified in Articles 4.12 and 4.13, respectively. The diagrams and drawings shall indicate the quantities, ratings, and operating parameters of the following:

- (a) Equipment (*e.g.*, Generating Unit, power Transformer, and Circuit Breaker);
- (b) Electrical circuits (*e.g.*, overhead lines and underground cables);
- (c) Substation bus arrangements;
- (d) Grounding arrangements;
- (e) Phasing arrangements; and
- (f) Switching facilities.

5.4.3.4 The User shall provide the values of the following circuit parameters of the overhead lines and/or underground cables from the User's substation to the Connection Point in the Distribution System:

- (a) Rated and operating Voltage (kV);
- (b) Positive sequence resistance and reactance (ohm);
- (c) Positive sequence shunt susceptance (Siemens or ohm^{-1});
- (d) Zero sequence resistance and reactance (ohm); and
- (e) Zero sequence susceptance (Siemens or ohm^{-1}).

5.4.3.5 If the User System is connected to the Distribution System through a step-up Transformer, the following data for the power Transformers shall be provided:

- (a) Rated MVA;

- (b) Rated Voltages (kV);
 - (c) Winding arrangement;
 - (d) Positive sequence resistance and reactance (at max, min, and nominal tap);
 - (e) Zero sequence reactance for three-legged core type Transformer;
 - (f) Tap changer range, step size and type (on-load or off-load); and
 - (g) Basic Lightning Impulse Insulation Level (kV).
- 5.4.3.6 The User shall provide the following information for the switchgear, including Circuit Breakers, Load break switches, and disconnect switches at the Connection Point and at the substation of the User:
- (a) Rated Voltage (kV);
 - (b) Rated current (A);
 - (c) Rated symmetrical RMS short-circuit current (kA); and
 - (d) Basic Lightning Impulse Insulation Level (kV).
- 5.4.3.7 The User shall provide the details of its System Grounding. This shall include the rated capacity and impedances of the Grounding Equipment.
- 5.4.3.8 The User shall provide the data on independently-switched Reactive Power compensation Equipment at the Connection Point and at the substation of the User. This shall include the following information:
- (a) Rated Capacity (MVAR);
 - (b) Rated Voltage (kV);
 - (c) Type (*e.g.*, shunt inductor, shunt capacitor, static var compensator); and
 - (d) Operation and control details (*e.g.*, fixed or variable, automatic, or manual).
- 5.4.3.9 If a significant portion of the User's Demand may be supplied from an alternative Connection Point, the relevant information on the Demand transfer capability shall be provided by the User including the following:
- (a) The alternative Connection Point;
 - (b) The Demand normally supplied from each alternative Connection Point;
 - (c) The Demand which may be transferred from or to each alternative Connection Point; and
 - (d) The control (*e.g.*, manual or automatic) arrangements for transfer including the time required to effect the transfer for Forced Outage and planned maintenance conditions.
- 5.4.3.10 If the User has an Embedded Generating Plants and/or significantly large motors, the short circuit contributions of the Generating Units and the large motors at the Connection Point shall be provided by the User. The short circuit current shall be calculated in accordance with the international standards (*e.g.*, ANSI/IEEE, IEC).

5.5 DETAILED PLANNING DATA

5.5.1 Embedded Generating Unit Data

5.5.1.1 All Conventional Embedded Generation Company shall provide the Distribution Utility the following additional information for its Generating Unit or Generating Plant:

- (a) Derated Capacity (MW) on a monthly basis, if applicable;
- (b) Additional capacity (MW) obtainable from Generating Units in excess of Net Declared Capacity;
- (c) Minimum Stable Loading (MW);
- (d) Reactive Power Capability Curve;
- (e) Stator armature resistance;
- (f) Direct axis synchronous, transient, and subtransient reactances;
- (g) Quadrature axis synchronous, transient, and subtransient reactances;
- (h) Direct axis transient and subtransient time constants;
- (i) Quadrature axis transient and subtransient time constants;
- (j) Turbine and Generating Unit inertia constant (MWsec/MVA);
- (k) Rated field current (A) at rated MW and MVAR output and at rated terminal Voltage; and
- (l) Short circuit and open circuit characteristic curves.

5.5.1.2 The following information shall be provided by the Embedded Generation Company for their Wind Generating Plant:

- (a) Dynamic model of the Wind Farm. In case the Wind Turbine Generating Units in the Wind Farm are not identical, the model shall incorporate separate modules to represent each type of Wind Turbine Generating Unit. Appropriate data and parameter values must be provided for each model. The dynamic model must represent the features and phenomena likely to be relevant to angular and Voltage Stability, such as Generating Plant model, blade pitch control, model of drive train and model of converter, if any;
- (b) Reactive compensation. Provide the details of reactive compensation, operating Power Factor range;
- (c) Wind Turbine Transformer data;
- (d) Transformer Voltage ratio;
- (e) Transformer data;
- (f) Percentage impedance;
- (g) Voltage ratio;
- (h) Winding connection; and
- (i) Tap settings.

5.5.1.3 The following information shall be provided by the Embedded Generation Company for their PVSS:

- (a) Solar Panel Data;
- (b) Solar Panel Manufacturer;
- (c) Rated Power per Solar Panel (kW);

- (d) Solar Panel Generating Unit Technology;
- (e) Rated Apparent Power (kVA);
- (f) Frequency Tolerance Range (Hz);
- (g) Width (mm);
- (h) Height (mm);
- (i) Area (m²);
- (j) Rated Voltage (Volt);
- (k) Rated Current (A);
- (l) Watts per square meter;
- (m) Efficiency (%);
- (n) Dynamic model of the PVS: Provide a dynamic model compatible with standard dynamic simulation tools;
- (o) Reactive compensation: Provide details of reactive compensation and operating Power Factor range; and
- (p) PVS Configuration: Single line diagram of connection scheme and details of the conductor used.

5.5.1.4 The Embedded Generation Company shall provide the Distribution Utility the following information on Step-up Transformers for its Generating Unit or Generating Plant:

- (a) Rated MVA;
- (b) Rated Frequency (Hz);
- (c) Rated Voltage (kV);
- (d) Power Factor;
- (e) Voltage ratio;
- (f) Positive sequence reactance (maximum, minimum, and nominal tap);
- (g) Positive sequence resistance (maximum, minimum, and nominal tap);
- (h) Zero sequence reactance;
- (i) Tap changer range;
- (j) Tap changer step size; and
- (k) Tap changer type: on load or off circuit.

5.5.1.5 The Conventional or VRE Embedded Generation Company shall provide the Distribution Utility the following excitation control system parameters for its Generating Unit or Generating Plant:

- (a) DC gain of Excitation Loop;
- (b) Rated field Voltage;
- (c) Maximum field Voltage;
- (d) Minimum field Voltage;
- (e) Maximum rate of change of field Voltage (rising);
- (f) Maximum rate of change of field Voltage (falling);
- (g) Details of Excitation Loop described in diagram form showing transfer functions of individual elements;
- (h) Dynamic characteristics of overexcitation limiter; and

(i) Dynamic characteristics of underexcitation limiter.

5.5.1.6 All Conventional Embedded Generation Company shall provide the Distribution Utility the following speed-governing parameters for reheat steam Generating Units or Generating Plants:

- (a) High pressure governor average gain (MW/Hz);
- (b) Speeder motor setting range;
- (c) Speed droop characteristic curve;
- (d) High pressure governor valve time constant;
- (e) High pressure governor valve opening limits;
- (f) High pressure governor valve rate limits;
- (g) Reheater time constant (Active Energy stored in reheater);
- (h) Intermediate pressure governor average gain (MW/Hz);
- (i) Intermediate pressure governor setting range;
- (j) Intermediate pressure governor valve time constant;
- (k) Intermediate pressure governor valve opening limits;
- (l) Intermediate pressure governor valve rate limits;
- (m) Details of acceleration sensitive elements in high pressure and intermediate pressure governor loop; and
- (n) A governor block diagram showing the transfer functions of individual elements.

5.5.1.7 All Conventional Embedded Generation Company shall provide the Distribution Utility the following speed-governing parameters for non-reheat steam, gas turbine, geothermal, and hydro Generating Units or Generating Plants:

- (a) Governor average gain;
- (b) Speeder motor setting range;
- (c) Speed droop characteristic curve;
- (d) Time constant of steam or fuel governor valve or water column inertia;
- (e) Governor valve opening limits;
- (f) Governor valve rate limits; and
- (g) Time constant of turbine.

5.5.1.8 The Embedded Generation Company shall provide the Distribution Utility the following plant flexibility performance data for its Generating Unit or Generating Plant:

- (a) Rate of loading following weekend Shutdown (Generating Unit and Generating Plant);
- (b) Rate of loading following an overnight Shutdown (Generating Unit and Generating Plant);
- (c) Block Load following synchronizing;
- (d) Rate of Load Reduction from normal rated MW;
- (e) Regulating range; and
- (f) Load rejection capability while still Synchronized and able to supply load.

5.5.1.9 The Embedded Generation Company shall provide the Distribution Utility the following auxiliary Demand data for its Generating Unit or Generating Plant:

- (a) Normal unit-supplied auxiliary Load for each Generating Unit at rated MW output; and
- (b) Each Generating Plant auxiliary Load other than (a) above and where the station auxiliary Load is supplied from the Distribution System.

5.5.2 User System Data

5.5.2.1 Large Customers and other Users connected to the Distribution System shall submit to the Distribution Utility the following Load characteristics:

- (a) Maximum Demand on each phase at peak load condition;
- (b) The Voltage Unbalance; and
- (c) The harmonic content.

5.5.2.2 The Distribution Utility and the User shall exchange information, including details of physical and electrical layouts, parameters, specifications, and protection, needed to conduct an assessment of transient Overvoltage effects in the Distribution System or the User System.

5.5.2.3 The User shall provide any additional planning data that may be requested by the Distribution Utility.

CHAPTER 6

DISTRIBUTION OPERATIONS

6.1 PURPOSE

- (a) To define the operational responsibilities of the Distribution Utilities and all Users of the Distribution System;
- (b) To specify the operational arrangements for mutual assistance, Equipment and inventory sharing, and joint purchases among Distribution Utilities;
- (c) To specify the requirements for communication and the notices to be issued by the Distribution Utility to Users and the notices to be issued by Users to the Distribution Utility and other Users.
- (d) To specify the Maintenance Programs for the Equipment and facilities in the Distribution System;
- (e) To describe the Demand Control strategies used for the control of the System Frequency and the methods used for Voltage Control;
- (f) To specify the procedures to be followed by the Distribution Utility and Users during emergency conditions;
- (g) To specify the procedures for the coordination, establishment, maintenance, and cancellation of Safety Precautions when work or testing other than System Test is to be carried out on the Distribution System or the User System;
- (h) To specify the procedures for testing and monitoring the quality of power supplied to the Distribution System and the User System;
- (i) To establish a procedure for the conduct of System Tests which involve the simulation of conditions or the controlled application of unusual or extreme conditions that may have an impact on the Distribution System or the User System;
- (j) To identify the tests and the procedures that need to be carried out to confirm the compliance of an Embedded Generating Unit with its registered parameters and its ability to provide Ancillary Services; and
- (k) To specify the requirements for Site and Equipment Identification at the Connection Point.

6.2 OPERATIONAL RESPONSIBILITIES

6.2.1 Operational Responsibilities of the Distribution Utility

- 6.2.1.1 The Distribution Utility shall be responsible for operating and maintaining Power Quality in the Distribution System during normal conditions, in accordance with the provision of Article 3.2, and in proposing solutions to Power Quality problems.
- 6.2.1.2 The Distribution Utility is responsible for preparing the Distribution Maintenance Program for the maintenance of its Equipment and facilities.
- 6.2.1.3 The Distribution Utility is responsible for providing and maintaining all Distribution Equipment and facilities.

6.2.1.4 The Distribution Utility is responsible for designing, installing, and maintaining a distribution protection system that will ensure the timely disconnection of faulted facilities and Equipment.

6.2.1.5 The Distribution Utility is responsible for ensuring that safe and economic distribution operating procedures are complied with.

6.2.1.6 The Distribution Utility is responsible for maintaining an Automatic Load Dropping scheme, as necessary, to meet the targets agreed upon with the System Operator.

6.2.1.7 The Distribution Utility is responsible for developing and proposing Distribution Wheeling Charges to the ERC.

6.2.2 Operational Responsibilities of Embedded Generation Companies

6.2.2.1 The Embedded Generation Company is responsible for ensuring that its Generating Units can deliver the capabilities declared in its Connection Agreement or Amended Connection Agreement.

6.2.2.2 The Embedded Generation Company is responsible for providing accurate and timely planning and operations data to the Distribution Utility.

6.2.2.3 The Embedded Generation Company is responsible for executing the instructions of the Distribution Utility during Normal, Alert or Emergency conditions.

6.2.2.4 The Embedded Generation Company shall be responsible for ensuring that its Generating Units will not disconnect from the Distribution System during disturbances except when:

- (a) The Frequency or Voltage Variation would damage the Equipment of the Generation Company; or
- (b) The Frequency or Voltage Variation is outside the prescriptions contained in Chapter 4; or
- (c) When the Distribution Utility has authorized the Generation Company to do so.

6.2.3 Operational Responsibilities of Large VRE Embedded Generation Companies

6.2.3.1 In Normal State, Large VRE Embedded Generating Plants shall be operated in the Free Active Power Production control mode (as defined in the latest edition of the Philippine Grid Code) or at any other control mode in case the Embedded Generation Company decides so.

6.2.3.2 In Alert State, the System Operator through the Distribution Utility shall make its best endeavors to permit Large VRE Embedded Generating Plants to continue operating in the Free Active Power Production control mode (as defined in the latest edition of the Philippine Grid Code). However, where necessary to maintain Security in the system, the System Operator through the Distribution Utility may instruct the Embedded Generating Plant personnel to change the Active Power control mode of their Generating Plants to any of those established in Section 4.6.5.

- 6.2.3.3 In Emergency, Extreme or Restorative States the System Operator through the Distribution Utility, or the Distribution Utility independently, shall issue appropriate instructions to Large VRE Embedded Generating Plants regarding the operation of this type of facilities. For the avoidance of doubt, these instructions may include the immediate disconnection of Large VRE Embedded Generating Plants from the network.
- 6.2.3.4 Large VRE Embedded Generating Plants shall permanently maintain Embedded Generating Plant personnel capable to properly execute the instructions issued by the System or Distribution Utility.
- 6.2.3.5 Embedded Generating Plant personnel shall promptly follow the instructions issued by the Distribution Utility or the System Operator through the Distribution Utility, implementing the actions requested in the Embedded Generating Plant control system without any intentional delay.
- 6.2.3.6 Any instruction issued by the System Operator to Large VRE Embedded Generation Company through the Distribution Utility implying a change in the Active Power Production control mode shall be clearly reflected in the weekly reports on Grid Operation, containing an explanation of the causes and an assessment of the performance of the Large VRE Embedded Generating Plant personnel in complying with the instructions.

6.2.4 Scheduling and Dispatch

Embedded Generation Companies that intend to register or are registered in the WESM shall comply with the requirements of the Scheduling and Dispatch Chapter of the Philippine Grid Code.

6.2.5 Operational Responsibilities of Other Distribution Users

- 6.2.5.1 The User is responsible for assisting the Distribution Utility in maintaining Power Quality in the Distribution System during normal conditions by correcting any User facility that causes Power Quality problems.
- 6.2.5.2 The User shall be responsible for ensuring that its System will not cause any Degradation of the Distribution System. It shall also be responsible in undertaking all necessary measures to remedy any degradation that the User System has caused to the Distribution System.
- 6.2.5.3 The User is responsible for executing the instructions of the Distribution Utility during emergency conditions.

6.3 OPERATIONAL ARRANGEMENTS

6.3.1 Mutual Assistance

- 6.3.1.1 The DMC shall recommend emergency procedures to the Distribution Utilities, including the development of a mutual assistance program for Distribution Utilities.
- 6.3.1.2 The Distribution Utilities shall cooperate in the establishment of mutual assistance procedures and in providing coordinated responses during emergencies.

6.3.2 Equipment and Inventory Sharing

6.3.2.1 The DMC shall recommend procedures for Equipment and inventory sharing to the Distribution Utilities, including the development of an Equipment and inventory sharing program for Distribution Utilities.

6.3.2.2 The Distribution Utilities shall cooperate in the establishment of procedures for Equipment and inventory sharing and in the implementation of an Equipment and inventory sharing program that will minimize procurement cost.

6.3.3 Joint Purchases

6.3.3.1 The DMC shall recommend procedures for joint purchase arrangements to the Distribution Utilities, including the development of a joint purchase program for Distribution Utilities.

6.3.3.2 The Distribution Utilities shall cooperate in the establishment of procedures for the joint purchase of Equipment and in the implementation of a joint purchase program to achieve economies of scale in the procurement of Equipment and supplies.

6.4 DISTRIBUTION OPERATIONS COMMUNICATIONS, NOTICES, AND REPORTS

6.4.1 Distribution Operations Communications

6.4.1.1 The Distribution Utility and the User shall establish a communication channel for the exchange of information required for distribution and open access operation. The communication channel shall, as much as possible, be direct between the Distribution Utility and the User, and between the Distribution Utility and the Supplier.

6.4.1.2 Where it is determined by the Distribution Utility that a backup or alternative route of communication and/or emergency communication is necessary for the safe operation of the Distribution System, the Distribution Utility and the User shall agree on the additional means of communication.

6.4.1.3 The Distribution Utility and the User shall provide the other with the names and contact numbers of their respective duly authorized personnel so that control activities can be efficiently coordinated, and maintain the 24-hour availability of these personnel.

6.4.2 Distribution Operations Notices

6.4.2.1 A Significant Incident Notice shall be issued by the Distribution Utility or any User if a Significant Incident has transpired in the Distribution System or the System of the User, as the case may be; copy furnished the Supplier, if applicable. The notice shall be issued within 15 minutes from the occurrence of the Significant Incident, and shall identify the possible consequences on the Distribution System and/or the System of other Users and any initial corrective measures that were undertaken by the Distribution Utility or the User, as the case may be.

6.4.2.2 A Planned Activity Notice shall be issued by a User to the Distribution Utility, and if applicable, to the Supplier for any planned activity such as a planned Shutdown or Scheduled Maintenance of its Equipment at least 3 days prior to the actual Shutdown or maintenance.

6.4.3 Distribution Operations Reports

6.4.3.1 The Distribution Utility shall prepare and submit to the DMC monthly reports on distribution operation. These reports shall include an evaluation of the Events and other problems that occurred within the Distribution System for the previous month, the measures undertaken by the Distribution Utility to address them, and the recommendations to prevent their recurrence.

6.4.3.2 The Distribution Utility shall submit to the DMC the Significant Incident Reports prepared pursuant to the provisions of Section 6.7.2.

6.4.3.3 The Distribution Utility shall prepare and submit to the DMC an annual operations report. This report shall include the Significant Incidents on the Distribution System that had a Material Effect on the Distribution System or the System of any User.

6.5 DISTRIBUTION MAINTENANCE PROGRAM

6.5.1 Preparation of Maintenance Program

6.5.1.1 The Distribution Utility shall prepare the following Distribution Maintenance Programs based on forecasted Demand, User's provisional Maintenance Program, and requests for maintenance schedule:

- (a) Three-Year Maintenance Program;
- (b) Annual Maintenance Program; and
- (c) Monthly Maintenance Program;

6.5.1.2 The three-year Maintenance Program shall be prepared annually for the three succeeding years. The annual Maintenance Program shall be developed based on the maintenance schedule for the first year of the three-year Maintenance Program. The monthly Maintenance Program shall provide the details required by the System Operator for the preparation of the Grid Operating Program, as specified in the Philippine Grid Code.

6.5.1.3 The Distribution Maintenance Program shall be developed taking into account the following:

- (a) The forecasted Demand;
- (b) The Maintenance Program actually implemented;
- (c) The requests by Users for changes in their maintenance schedules;
- (d) The requirements for the maintenance of the Grid;
- (e) The need to minimize the total cost of the required maintenance; and
- (f) Any other relevant factors.

6.5.2 Submission and Approval of Maintenance Program

6.5.2.1 The User shall provide the Distribution Utility by week 23 of the current year a provisional Maintenance Program for the three succeeding

years. The following information shall be included in the User's provisional Maintenance Program and when the User requests for a maintenance schedule for its System or Equipment:

- (a) Identification of the Equipment and the MW capacity involved;
- (b) Reasons for the maintenance;
- (c) Expected duration of the maintenance work;
- (d) Preferred start date for the maintenance work and the date by which the work shall have been completed; and
- (e) If there is flexibility in dates, the earliest start date and the latest Completion Date.

6.5.2.2 The Maintenance Program submitted by the Embedded Generation Company for its Scheduled Generating Units shall be submitted by the Distribution Utility to the Transmission Network Provider by week 27 of the current year.

6.5.2.3 The Distribution Utility shall endeavor to accommodate the User's request for maintenance schedule at particular dates in preparing the Distribution Maintenance Program.

6.5.2.4 The Distribution Utility shall provide the User a written copy of the User's approved Maintenance Program.

6.5.2.5 If the User is not satisfied with the Maintenance Schedule allocated to its Equipment, it shall notify the Distribution Utility to explain its concern and to propose changes in the Maintenance Program. The Distribution Utility and the User shall discuss and resolve the problem. The Maintenance Program shall be revised by the Distribution Utility based on the resolution of the User's concerns.

6.6 DEMAND AND VOLTAGE CONTROL

6.6.1 Demand Control Coordination

6.6.1.1 The Distribution Utility shall implement Demand Control when the System Operator has issued a Red Alert notice due to a generation deficiency in the Grid or when a Multiple Outage Contingency resulted in Island Grid operation.

6.6.1.2 The Demand Control to be implemented by the Distribution Utility shall include the following:

- (a) Automatic Load Dropping;
- (b) Manual Load Dropping; and
- (c) Voluntary Demand Management.

6.6.1.3 If the System Operator has issued an instruction to implement Demand Control for the Security of the Grid, the Distribution Utility shall promptly implement the instruction of the System Operator.

6.6.1.4 If the Demand Control is to be undertaken by the Distribution Utility to safeguard its Distribution System, the Distribution Utility shall coordinate the Demand Control with the affected Users and its Supplier, as the case may be.

6.6.1.5 The Distribution Utility shall abide by the instruction of the System Operator with regard to the restoration of Demand. The restoration of Demand shall be achieved as soon as possible and the process of restoration shall begin within 2 minutes after the instruction is given by the System Operator.

6.6.1.6 If a User is disconnected due to Demand Control, the User shall not reconnect its System until instructed by the Distribution Utility to do so.

6.6.2 Automatic Load Dropping

6.6.2.1 The System Operator shall establish the level of Demand required for Under-Frequency Load Shedding (UFLS) and Under-Voltage Load Shedding (UVLS) in order to limit the consequences of Significant Incidents or a major loss of generation in the Grid. The System Operator shall conduct the appropriate technical studies to justify the targets and/or to refine them as necessary.

6.6.2.2 The Distribution Utility shall prepare its UFLS program in consultation with the System Operator. The Distribution Utility's Demand that is subject to UFLS shall be split into rotating discrete MW blocks. The System Operator shall specify the number of blocks and the underfrequency setting for each block.

6.6.2.3 If the Distribution Utility does not implement a UFLS program, the Transmission Network Provider shall install the Underfrequency Relay at the main feeder and the System Operator shall drop the User Demand as a single block, if the need arises.

6.6.2.4 To ensure that a subsequent fall in Frequency will be contained by the operation of UFLS, additional Manual Load Dropping shall be implemented by the Distribution Utility so that the loads that were dropped by UFLS can be reconnected.

6.6.2.5 If an ALD has taken place, the affected User shall not reconnect its disconnected feeder without clearance from the Distribution Utility. The Distribution Utility shall issue the order to reconnect upon instruction by the System Operator.

6.6.2.6 The Distribution Utility shall notify the System Operator of the actual Demand that was disconnected by UFLS, or the Demand that was restored in the case of reconnection, within 5 minutes of the Load dropping or reconnection.

6.6.2.7 The Distribution Utility shall notify the System Operator of the actual Demand that was disconnected by UVLS, or the Demand that was restored in the case of reconnection, within 5 minutes of the Load dropping or reconnection.

6.6.3 Manual Load Dropping

6.6.3.1 The Distribution Utility shall make arrangements that will enable it to disconnect its Customers immediately following the issuance by the System Operator of an instruction to implement MLD.

- 6.6.3.2 Distribution Utilities shall, in consultation with the System Operator, establish a priority scheme for MLD based on equitable load allocation.
- 6.6.3.3 If the System Operator has determined that the MLD carried out by the User is not sufficient to contain the decline in Grid frequency, the System Operator may disconnect the total Demand of the Distribution Utility in an effort to preserve the integrity of the Grid.
- 6.6.3.4 If the Distribution Utility disconnected its Customers upon the instruction of the System Operator, the Distribution Utility shall not reconnect the affected Customer until instructed by the System Operator to do so.
- 6.6.3.5 If the Distribution Utility disconnected a User System, the User shall not reconnect its System until instructed by the Distribution Utility to do so.

6.6.4 Voluntary Demand Management

- 6.6.4.1 If a User intends to implement for the following day Demand Control through a Demand Disconnection at the Connection Point, it shall notify the Distribution Utility of the hourly schedule before 0830 hours of the current day. The notification shall contain the following information:
- (a) The proposed (in the case of prior notification) and actual (in the case of subsequent notification) date, time, and duration of implementation of the Demand Disconnection; and
 - (b) The magnitude of the proposed reduction by the use of Demand Disconnection. The Distribution Utility shall provide the System Operator with the amount of Demand reduction actually achieved by the use of the Demand Disconnection.
- 6.6.4.2 If a User intends to implement for the following day Demand Control through a Customer Demand Management, it shall notify the Distribution Utility of the hourly schedule before 0830 hours of the current day. The notification shall contain the following information:
- (a) The proposed (in the case of prior notification) and actual (in the case of subsequent notification) date, time, and duration of implementation of the Customer Demand Management; and
 - (b) The magnitude of the proposed reduction by the use of Customer Demand Management. The Distribution Utility shall provide the System Operator with the amount of Demand reduction actually achieved by the use of the Customer Demand Management.
- 6.6.4.3 If the Demand Control involves the disconnection of an industrial circuit, Voluntary Load Curtailment (VLC) or any similar scheme shall be implemented wherein the Customers are divided into VLC Weekday groups (e.g., Monday Group, Tuesday Group, etc.). Customers participating in the VLC shall voluntarily reduce their respective Demands for a certain period of time depending on the extent of the generation deficiency. Industrial Customers or Commercial Customers who implemented a VLC shall provide the Distribution Utility with the amount of Demand reduction actually achieved through the VLC scheme.

6.6.5 Voltage Control

The control of Voltage can be achieved by managing the Reactive Power supply in the Distribution System. This shall include the operation of the following Equipment:

- (a) Embedded Generating Units;
- (b) Synchronous condensers;
- (c) Static VAR compensators;
- (d) Shunt capacitors and reactors; and
- (e) On-Load tap changing Transformers.

In order to perform the control of Voltage, the Distribution Utility will send the instructions it considers appropriate to the Large Conventional, Large VRE or Medium Embedded Generating Plant, provided such instructions imply providing Reactive Power within the limits indicated in Sections 4.5.5, 4.6.3 and 4.7.3, as appropriate.

6.7 EMERGENCY PROCEDURES

6.7.1 Preparation for Distribution Emergencies

6.7.1.1 The Distribution Utility shall issue a directive to any User for the purpose of mitigating the effects of the disruption of electricity supply attributable to any of the following:

- (a) Natural disaster;
- (b) Civil disturbance; or
- (c) Fortuitous Event.

6.7.1.2 The User shall provide the Distribution Utility, in writing, copy furnished the Supplier, the contact numbers of persons who can make binding decisions on the User System when there is a Significant Incident.

6.7.1.3 The Distribution Utility shall develop and maintain a Manual of Distribution Emergency Procedures, which shall include a list of all the parties to be notified in cases of emergencies, and their business and home contact numbers.

6.7.1.4 Emergency drills shall be conducted at least once a year to familiarize all personnel responsible for emergencies. The drills shall simulate realistic emergency situations. A drill evaluation shall be performed and deficiencies in procedures and responses shall be identified and corrected.

6.7.1.5 The User shall participate in all emergency drills organized by the Distribution Utility.

6.7.2 Significant Incident Procedures

6.7.2.1 Following the issuance of a Significant Incident Notice by the Distribution Utility or a User, any User may file a written request to the Distribution Utility for a joint investigation of the Significant Incident. If there have been several Significant Incidents, the joint investigation may include the other Significant Incidents.

6.7.2.2 A joint investigation of the Significant Incident shall be conducted only when the Distribution Utility and the Users have reached an agreement to conduct the joint investigation.

6.7.2.3 The Distribution Utility shall submit a written report to the DMC and the ERC detailing all the information, findings, and recommendations regarding the Significant Incident.

6.7.2.4 The following minimum information shall be included in the written report following the joint investigation of the Significant Incident:

- (a) Time and date of the Significant Incident;
- (b) Location of the Significant Incident;
- (c) Equipment directly involved and not merely affected by the Event;
- (d) Description of the Significant Incident; and
- (e) Demand (in MW) and generation (in MW) interrupted and the duration of the Interruption.

6.7.3 Operation of Embedded Generating Unit in Island Grid

6.7.3.1 If a part of the Distribution System to which an Embedded Generating Unit is connected becomes isolated from the Distribution System, both the Distribution Utility and the Embedded Generation Company shall determine and agree if it is possible and desirable for the Embedded Generating Unit to continue operating.

6.7.3.2 If no facilities exist for the subsequent resynchronization with the rest of the Distribution System, the Distribution Utility shall issue an instruction to the Embedded Generation Company to disconnect its Generating Unit so that the Island Grid may be reconnected to the rest of the Distribution System.

6.7.4 Black Start and Resynchronization Procedures

6.7.4.1 If a Significant Incident resulted in a Total System Blackout or a Partial System Blackout and the isolated Distribution System has Embedded Generating Units with Black Start Capability, the Distribution Utility shall initiate a Black Start procedure in coordination with the System Operator.

6.7.4.2 The System Operator, pursuant to the procedures in the latest edition of the Philippine Grid Code, shall be responsible in the resynchronization of the Island Grids after the Black Start procedure or after a Significant Incident has resulted in Island Grid operation.

6.7.4.3 After a Total System Blackout or a Partial System Blackout and during the whole restoration process, Embedded Generation Companies of Large and Medium Embedded Generating Plants shall strictly follow the instructions issued by the System Operator through the Distribution Utility. They shall not reconnect to the network unless an instruction or an authorization has been provided by the System Operator or the Distribution Utility.

6.8 SAFETY COORDINATION

6.8.1 Safety Coordination Procedures

- 6.8.1.1 The Distribution Utility and the User shall adopt and use a set of Safety Rules and Local Safety Instructions for implementing Safety Precautions on MV and HV Equipment. The respective Safety Rules and Local Safety Instructions of the Distribution Utility and the User shall govern any work or testing on the Distribution System or the User System.
- 6.8.1.2 The Distribution Utility shall furnish the User a copy of its Safety Rules and Local Safety Instructions relating to the Safety Precautions on its MV and HV Equipment.
- 6.8.1.3 The User shall furnish the Distribution Utility a copy of its Safety Rules and Local Safety Instructions relating to the Safety Precautions on its MV and HV Equipment.
- 6.8.1.4 Any party who wants to amend any provision of or revise its Local Safety Instructions shall provide the other party with the amended or revised copy of the Local Safety Instructions.
- 6.8.1.5 Safety coordination procedures shall be established for the coordination, establishment, maintenance, and cancellation of Safety Precautions on MV and HV Equipment when work or testing is to be carried out in the Distribution System or the User System.
- 6.8.1.6 Work or testing on any Equipment at the Connection Point shall be carried out only in the presence of the representatives of the Distribution Utility and the User.
- 6.8.1.7 The User (or the Distribution Utility) shall seek authority from the Distribution Utility (or the User) if it wishes to access any Distribution Utility's (or User's) Equipment.
- 6.8.1.8 If work or testing is to be carried out in the Distribution System and a Safety Precaution is required on the MV and HV Equipment of several Users, the Distribution Utility shall ensure that the Safety Precautions in the Distribution System and on the System of all Users involved are coordinated and implemented.
- 6.8.1.9 If work or testing is to be carried out in the Distribution System and a User becomes aware that Safety Precautions are also required in the System of other Users, the Distribution Utility shall be promptly informed of the required Safety Precautions in the System of the other Users. The Distribution Utility shall ensure that Safety Precautions are coordinated and implemented in the Distribution System and the Systems of the affected Users.

6.8.2 Safety Coordinator

- 6.8.2.1 The Distribution Utility and the User shall assign a Safety Coordinator who shall be responsible for the coordination of Safety Precautions on the MV and HV Equipment at their respective sides of the Connection Point. Any party who wants to change its Safety Coordinator shall notify the other party of the change.

- 6.8.2.2 For purposes of safety coordination, the Safety Coordinator requesting that a Safety Precaution be applied on the System of the other party shall be referred to as the Requesting Safety Coordinator while the Safety Coordinator that will implement the requested Safety Precaution shall be referred to as the Implementing Safety Coordinator.
- 6.8.2.3 If work or testing is to be carried out in the Distribution System (or the User System) that requires Safety Precautions on the MV and HV Equipment of the User System (or the Distribution System), the Requesting Safety Coordinator shall contact the Implementing Safety Coordinator to coordinate the necessary Safety Precautions.
- 6.8.2.4 If a Safety Precaution is required for the MV and HV Equipment of other Users who were not mentioned in the request, the Implementing Safety Coordinator shall promptly inform the Requesting Safety Coordinator.
- 6.8.2.5 If a Safety Precaution becomes ineffective, the concerned Safety Coordinator shall inform the other Safety Coordinators about it without delay, and stating the reasons why the Safety Precaution has lost its integrity.

6.8.3 Safety Logs and Record of Inter-System Safety Precautions

- 6.8.3.1 The Distribution Utility and the User shall maintain Safety Logs to record, in chronological order, all messages relating to Safety Coordination. The Safety Logs shall be retained for at least 1 year.
- 6.8.3.2 The Distribution Utility shall establish a record of inter-system Safety Precautions to be used by the Requesting Safety Coordinator and the Implementing Safety Coordinator in coordinating the Safety Precautions on MV and HV Equipment. The record of intersystem Safety Precautions shall contain the following information:
- (a) Site and Equipment Identification of MV or HV Equipment where the Safety Precaution is to be established or has been established;
 - (b) Location and the means of implementation of the Safety Precaution;
 - (c) Confirmation of the Safety Coordinator that the Safety Precaution has been established; and
 - (d) Confirmation of the Safety Coordinator that the Safety Precaution is no longer needed and has been cancelled.

6.8.4 Location of Safety Precautions

- 6.8.4.1 When work or testing is to be carried out in the Distribution System (or the User System) and Safety Precautions are required in the User System (or the Distribution System), the Requesting Safety Coordinator shall contact the concerned Implementing Safety Coordinator to agree on the locations where the Safety Precautions will be implemented or applied. The Requesting Safety Coordinator shall specify the proposed locations at which Isolation and/or Grounding are to be established.
- 6.8.4.2 In the case of Isolation, the Implementing Safety Coordinator shall promptly notify the Requesting Safety Coordinator of the following:

- (a) The Identification of each Point of Isolation using the Site and Equipment Identification specified in Article 6.12; and
 - (b) The means of implementing Isolation as specified in Section 6.8.5.
- 6.8.4.3 In the case of Grounding, the Implementing Safety Coordinator shall promptly notify the Requesting Safety Coordinator of the following:
- (a) The Identification of each Point of Grounding using the Site and Equipment Identification specified in Article 6.12; and
 - (b) The means of implementing Grounding as specified in Section 6.8.5.
- 6.8.4.4 If the Requesting Safety Coordinator and the Implementing Safety Coordinator do not agree on the location, Grounding shall be established at the available point on the infeed closest to the MV and HV Equipment.

6.8.5 Implementation of Safety Precautions

- 6.8.5.1 Once the locations of Isolation and Grounding have been agreed upon, the Implementing Safety Coordinator shall ensure that the Isolation is implemented.
- 6.8.5.2 The Isolation shall be implemented by any of the following:
- (a) A disconnect switch, or other isolating means, that is secured in an open position by a lock and affixing a Safety Tag to it or by such other method in accordance with the Local Safety Instructions of the Distribution Utility or of the User, as the case may be; or
 - (b) An adequate physical separation (*e.g.*, Grounding Cluster) in accordance with the Local Safety Instructions of the Distribution Utility or of the User. In addition, a Safety Tag shall be placed at the switching points.
- 6.8.5.3 The Implementing Safety Coordinator, after the required Isolation in all locations had been established in his System, shall notify the Requesting Safety Coordinator that the required Isolation has been implemented.
- 6.8.5.4 After the confirmation of Isolation, the Requesting Safety Coordinator shall inform the former of the establishment of relevant Isolation, if any, on his System and request, if required, the implementation of Grounding.
- 6.8.5.5 The Implementing Safety Coordinator shall ensure the implementation of Grounding and notify the Requesting Safety Coordinator that Grounding has been established in his System.
- 6.8.5.6 Grounding shall be implemented by any of the following:
- (a) A Grounding switch secured in a closed position by a lock and affixing a Safety Tag to it or by such other method in accordance with the Local Safety Instructions of the Distribution Utility or of the User, as the case may be; or
 - (b) An adequate physical connection (*e.g.*, Grounding Cluster) which shall be in accordance with the methods set out in the Local Safety Instructions of the Distribution Utility or those of the User. In addition, a Safety Tag shall be placed at the point of connection and all related switching points.

6.8.5.7 If the disconnect switch or the Grounding switch is locked with its own locking mechanism or with a padlock, the key shall be secured in a key cabinet.

6.8.6 Authorization of Testing

If the Requesting Safety Coordinator wishes to authorize a test on MV or HV Equipment, he shall only do so after the following procedure has been implemented:

- (a) Confirmation is obtained from the Implementing Safety Coordinator that no person is working on or testing, or has been authorized to work on or test, any part of his System within the Points of Isolation identified;
- (b) All Safety Precautions other than the current Safety Precautions have been cancelled; and
- (c) The Implementing Safety Coordinator agrees with him on the conduct of testing in that part of the System.

6.8.7 Cancellation of Safety Precautions

6.8.7.1 When the Requesting Safety Coordinator decides that Safety Precautions are no longer required, he shall contact the Implementing Safety Coordinator and inform him that the Safety Precautions are no longer required.

6.8.7.2 Both coordinators shall then cancel the Safety Precautions.

6.9 DISTRIBUTION TESTING AND MONITORING

6.9.1 Testing Requirements

6.9.1.1 The Distribution Utility shall, from time to time, determine the need to test and/or monitor the Power Quality at various points on its Distribution System.

6.9.1.2 The requirement for specific testing and/or monitoring by a Distribution Utility shall be initiated by the receipt of a complaint relating to Power Quality in the Distribution System.

6.9.1.3 In certain situations, the Distribution Utility may require the testing and/or monitoring to take place at the Connection Point of a User to be witnessed by a User representative.

6.9.1.4 If testing and/or monitoring is required at the Connection Point, the Distribution Utilities shall advise the User involved and shall make available the results of such tests to the User.

6.9.1.5 Upon the request of the User, a retest shall be carried out. The cost of the retest shall be charged to the User.

6.9.1.6 If the results of the test show that the User is operating outside the technical parameters specified in Sections 4.2.5, 4.2.6, and 4.2.7, the User shall be informed accordingly. The User shall rectify the situation within such period of time as agreed upon with the Distribution Utility.

6.9.1.7 If the User failed to rectify the situation, the Distribution Utility may disconnect the User from the Distribution System, in accordance with the Connection Agreement or Amended Connection Agreement.

6.9.2 Monitoring of User Effect on the Distribution System

6.9.2.1 The Distribution Utility shall, from time to time, monitor the effect of the User System in the Distribution System.

6.9.2.2 The monitoring shall normally be related to the amount of Active Power and Reactive Power transferred across the Connection Point.

6.9.2.3 If the User is exporting (or importing) from the Distribution System a Demand in excess of the value specified in the Connection Agreement or Amended Connection Agreement, the Distribution Utility shall inform the User. Upon the request of the User, the Distribution Utility shall demonstrate the results of such monitoring.

6.9.2.4 The User may request technical information from the Distribution Utility on the method of monitoring adopted, and if necessary, request to use another method that is acceptable to the Distribution Utility.

6.9.2.5 If the User is operating outside the limits specified in Sections 4.2.5, 4.2.6, and 4.2.7, the User shall immediately restrict the Demand transfer to within the value specified in the Connection Agreement or Amended Connection Agreement. The restriction shall be in effect until a new Amended Connection Agreement is signed and the necessary changes in the Connection Point are undertaken.

6.9.2.6 If the User's Demand is in excess of the rated capacity of the Connection Point, the User shall limit the Demand transfer to the value specified in the Connection Agreement or Amended Connection Agreement.

6.10 SYSTEM TEST

6.10.1 System Test Requirements

6.10.1.1 System Test, which involves the simulation of conditions or the controlled application of unusual or extreme conditions that may have an impact on the Distribution System or the User System, shall be carried out in a manner that shall not endanger any personnel or the general public.

6.10.1.2 The possibility of damage to Equipment, the Distribution System, and the System of the Users shall be minimized when undertaking a System Test on the Distribution System or the User System.

6.10.1.3 Where the System Test may have an impact on the Grid, the procedure specified in the Philippine Grid Code shall be used in carrying out the proposed System Test.

6.10.2 System Test Request

6.10.2.1 If a User wishes to undertake a System Test on its System, it shall submit to the Distribution Utility a System Test Request that contains the following:

- (a) The purpose and nature of the proposed System Test;

- (b) The extent and condition of the Equipment involved; and
- (c) A proposed System Test Procedure specifying the switching sequence and the timing of the switching sequence.

6.10.2.2 The System Test Proponent shall provide sufficient time for the Distribution Utility to plan the proposed System Test. The Distribution Utility shall determine the time required for each type of System Test.

6.10.2.3 The Distribution Utility may require additional information before approving the proposed System Test if the information contained in the System Test Request is insufficient, or the proposed System Test Procedure cannot ensure the safety of personnel and Reliability of the Distribution System.

6.10.2.4 The Distribution Utility shall determine and notify other Users other than the System Test Proponent that may be affected by the proposed System Test.

6.10.2.5 The Distribution Utility may also initiate a System Test if it determined that the System Test is necessary to ensure the safety and Reliability of the Distribution System.

6.10.3 System Test Group

6.10.3.1 If the Distribution Utility is the System Test Proponent, it shall notify all affected Users of the proposed System Test. If the Distribution Utility is not the System Test Proponent, it shall notify, within 1 month after the acceptance of a System Test Request, the System Test Proponent and the affected Users of the proposed System Test. The notice shall contain the following:

- (a) The purpose and nature of the proposed System Test, the extent and condition of the Equipment involved, the identity of the System Test Proponent, and the affected Users;
- (b) An invitation to nominate representatives for the System Test Group to be established to coordinate the proposed System Test; and
- (c) If the System Test involves work or testing on MV and HV Equipment, the Safety Coordinators and the safety procedure specified in Article 6.8.

6.10.3.2 The Distribution Utility, the System Test Proponent (if it is not the Distribution Utility) and the affected Users shall nominate their representatives to the System Test Group within 1 month after receipt of the notice from the Distribution Utility. The Distribution Utility may decide to proceed with the proposed System Test even if the affected Users fail to reply within that period.

6.10.3.3 The Distribution Utility shall establish a System Test Group and appoint a System Test Coordinator, who shall act as chairman of the System Test Group. The System Test Coordinator may come from the Distribution Utility or the System Test Proponent.

6.10.3.4 The members of the System Test Group shall meet within 1 month after the Test Group is established. The System Test Coordinator shall convene the System Test Group as often as necessary.

6.10.3.5 The agenda for the meeting of the System Test Group shall include the following:

- (a) The details of the purpose and nature of the proposed System Test and other matters included in the System Test Request;
- (b) Evaluation of the System Test Procedure as submitted by the System Test Proponent and making the necessary modifications to come up with the final System Test Procedure;
- (c) The possibility of scheduling simultaneously the proposed System Test with any other test and with Equipment Maintenance which may arise pursuant to the Maintenance Program requirements of the Distribution System or the System of the Users; and
- (d) The economic, operational, and risk implications of the proposed System Test on the Distribution System, the System of the other Users, and the Scheduling and Dispatch of the Embedded Generating Plants.

6.10.3.6 The Distribution Utility, the System Test Proponent (if it is not the Distribution Utility) and the affected Users (including those which are not represented in the System Test Group) shall provide the System Test Group, upon request, with such details as the System Test Group reasonably requires to carry out the proposed System Test.

6.10.4 System Test Program

6.10.4.1 Within 2 months after the first meeting and at least 1 month prior to the date of the proposed System Test, the System Test Group shall submit to the Distribution Utility, the System Test Proponent (if it is not the Distribution Utility), and the affected Users a proposed System Test Program which shall contain the following:

- (a) Plan for carrying out the System Test;
- (b) System Test Procedure to be followed during the test including the manner in which the System Test is to be monitored;
- (c) List of responsible persons, including Safety Coordinators when necessary, who will be involved in carrying out the System Test;
- (d) An allocation of the testing cost among the affected parties; and
- (e) Such other matters as the System Test Group may deem appropriate and necessary and are approved by the management of the affected parties.

6.10.4.2 If the proposed System Test Program is acceptable to the Distribution Utility, the System Test Proponent, and the affected Users, the final System Test Program shall be constituted and the System Test shall proceed accordingly. Otherwise, the System Test Group shall revise the System Test Program.

6.10.4.3 If the System Test Group is unable to develop a System Test Program or reach a decision in implementing the System Test Program, the Distribution Utility shall determine whether it is necessary to proceed with the System Test to ensure the safety and Reliability of the Distribution System.

6.10.4.4 The System Test Coordinator shall be notified in writing, as soon as possible, of any proposed revision or amendment to the System Test Program prior to the day of the proposed System Test. If the System Test Coordinator decides that the proposed revision or amendment is meritorious, he shall notify the Distribution Utility, the System Test Proponent and the affected Users to act accordingly for the inclusion thereof. The System Test Program shall then be carried out with the revisions or amendments if the System Test Coordinator received no objections.

6.10.4.5 If System conditions are abnormal during the scheduled day for the System Test, the System Test Coordinator may recommend a postponement of the System Test.

6.10.5 System Test Report

6.10.5.1 Within 2 months or a shorter period as the System Test Group may agree after the conclusion of the System Test, the System Test Proponent shall prepare and submit a System Test Report to the Distribution Utility, the affected Users, and the members of the System Test Group.

6.10.5.2 After the submission of System Test Report, the System Test Group shall be automatically dissolved.

6.10.5.3 The Distribution Utility shall submit the System Test Report to the DMC for its review and recommendations.

6.11 EMBEDDED GENERATING UNIT CAPABILITY TESTS

6.11.1 Test Requirements For Large and Medium Embedded Generating Units

6.11.1.1 Tests shall be conducted, in accordance with the agreed procedures and standards, to confirm the compliance of Large and Medium Embedded Generating Units for the following:

- (a) Capability of Generating Units to operate within their registered Generation parameters;
- (b) Capability of the Generating Units to meet the applicable requirements of the Philippine Grid Code and the Philippine Distribution Code;
- (c) Capability to deliver the Ancillary Services that the Embedded Generation Company had agreed to provide; and
- (d) Availability of Generating Units in accordance with their capability declaration.

6.11.1.2 All tests shall be recorded and witnessed by the authorized representatives of the Distribution Utility, Embedded Generation Company, and/or User.

6.11.1.3 The Embedded Generation Company shall demonstrate to the Distribution Utility the reliability and accuracy of the test instruments and Equipment to be used in the test.

6.11.1.4 The Distribution Utility may at any time, issue instructions requiring tests to be carried out on any Large and Medium Embedded Generating Unit. All tests shall be of sufficient duration and shall be conducted no

more than twice a year except when there are reasonable grounds to justify the necessity for further tests.

6.11.1.5 If an Embedded Generating Unit fails the test, the Embedded Generation Company shall correct the deficiency within an agreed period to attain the relevant registered parameters for that Embedded Generating Unit.

6.11.1.6 Once the Embedded Generation Company achieves the registered parameters of its Embedded Generating Unit that previously failed the test, it shall immediately notify the Distribution Utility. The Distribution Utility shall then require the Embedded Generation Company to conduct a retest in order to demonstrate that the appropriate parameter has already been restored to its registered value.

6.11.1.7 If a dispute arises relating to the failure of an Embedded Generating Unit to pass a given test, the Distribution Utility, the Embedded Generation Company, and/or User shall seek to resolve the dispute among themselves.

6.11.1.8 If the dispute cannot be resolved, one of the parties may submit the issue to the ERC, through the DMC.

6.11.2 Tests to be Performed for Large and Medium Embedded Generating Units

6.11.2.1 The Reactive Power Test shall demonstrate that the Large or Medium Embedded Generating Unit meets the registered Reactive Power Capability requirements specified in Sections 4.5.5, 4.6.3 or 4.7.3 as applicable. The Embedded Generating Unit shall pass the test if the measured values are within $\pm 5\%$ of the Capability as registered with the Transmission Network Provider through the Distribution Utility.

6.11.2.2 The Frequency Withstand Test shall demonstrate that the Large or Medium Embedded Generating Unit has the capability to remain Synchronized to the network for the time prescribed in Sections 4.5.2, 4.6.2 or 4.7.2, as applicable. The Generating Unit shall pass the test if it does not disconnect when System Frequency is within the permissible values.

6.11.2.3 The Primary Response Test shall demonstrate that the Large or Medium Embedded Generating Unit has the capability to provide Primary Response, as specified in Section 4.5.7, 4.6.5 or 4.7.4, as applicable. The Generating Unit shall pass the test if the measured response in MW/Hz is within $\pm 5\%$ of the required level of response within 5 seconds.

6.11.2.4 The Reactive Power Control Test shall demonstrate that the Large or Medium Embedded Generating Unit has the capability to control the Reactive Power at the Connection Point, as specified in Section 4.5.6, 4.6.4 or 4.7.3, as applicable. The Embedded Generating Plant shall pass the test if:

- (a) In Voltage control mode, the Large Embedded Generating Plant is capable to control the Voltage at the Connection Point within a margin not greater than 0.01 p.u., provided the Reactive Power injected or absorbed is within the limits specified in Section 4.5.5 or 4.6.3, as

corresponds, with a steady state reactive tolerance no greater than 5% of the maximum Reactive Power.

- (b) Following a step change in Voltage, the Large Embedded Generating Unit shall be capable of achieving 90% of the change in Reactive Power output within a time less than 5 seconds, reaching its final value within a time no greater than 30 seconds.
- (c) In Power Factor control mode, the Large or Medium Embedded Generating Plant is capable of controlling the Power Factor at the Connection Point within the required Reactive Power range, with a target Power Factor in steps no greater than 0.01.

6.11.2.5 The Fast Start Capability Test shall demonstrate that the Embedded Generating Unit has the capability to automatically Start-Up, synchronize with the Grid through the Distribution System and be loaded up to its offered capability, as specified in Section 4.4.4. The Embedded Generating Unit shall pass the test if it meets the Fast Start capability requirements.

6.11.2.6 The Black Start Test shall demonstrate that the Embedded Generating Unit with Black Start capability can implement a Black Start procedure, as specified in Section 4.4.3. To pass the test, the Embedded Generating Unit shall start on its own, synchronize with the Grid through the Distribution System and carry load without the need for external power supply.

6.11.2.7 The Declared Data Capability Test, to be performed to Large Conventional or Large VRE, Medium Embedded Generation Company shall demonstrate that the Embedded Generating Unit can be scheduled and dispatched in accordance with the Declared Data. To pass the test, the Embedded Generating Unit shall satisfy the ability to achieve the Declared Data.

6.11.2.8 The Dispatch Accuracy Test, to be performed to Large or Medium Embedded Generation Company shall demonstrate that the Embedded Generating Unit meets the relevant Dispatch Scheduling and Dispatch Parameters. The Embedded Generating Unit shall pass the test if:

- (a) In the case of synchronization, the process is achieved within ± 5 minutes of the registered synchronization time;
- (b) In the case of synchronizing generation (if registered as a Dispatch Scheduling and Dispatch Parameters), the synchronizing generation achieved is within an error level equivalent to 2.5% of Net Declared Capacity;
- (c) In the case of meeting ramp rates, the actual ramp rate is within $\pm 10\%$ of the registered ramp rate;
- (d) In the case of meeting Load reduction rates, the actual Load reduction rate is within $\pm 10\%$ of the registered load reduction rate; and
- (e) In the case of all other Dispatch Scheduling and Dispatch Parameters, values are within $\pm 1.5\%$ of the declared values.

6.11.2.9 The SCADA and communications tests shall demonstrate that the Large or Medium Embedded Generating Unit is capable to:

- (a) Receive active power or Voltage set-points and/or disconnection signals issued from the Distribution Utility or from the System Operator SCADA through the Distribution Utility, provided that such possibilities has been agreed in the Connection Agreement and/or Amended Connection Agreement; and
- (b) Send to the Distribution Utility the signals indicated in the Connection Agreement or Amended Connection Agreement.

6.11.2.10 The Protections Tests shall demonstrate that all the protections agreed with the Distribution Utility perform with the required speed and selectivity settings. It shall also demonstrate that the Embedded Generating Unit disconnects from the Distribution System in case of Loss of Mains.

6.11.2.11 The Ancillary Services acceptability test shall determine the committed services in terms of parameter quantity or volume, timeliness, and other operational requirements. Generation Companies providing Ancillary Services shall conduct the test or define the committed service. However, monitoring by the System Operator or the Distribution Utility of the Ancillary Services performance in response to System-derived inputs shall also be carried out.

6.11.2.12 Following tests can be performed for Large or Medium Embedded Generating Units in cases that, based on an analysis of one or more network incidents or claims, the System Operator, the Distribution Utility, the DMC or the ERC has grounds to consider the performance of the Embedded Generating Plant is not complying with the prescriptions stated in the Philippine Distribution Code:

- (a) The Power Quality test shall demonstrate that the Embedded Generating Plant complies with the requirements specified in Section 4.4.5. The Embedded Generating Plant shall pass the test if the Flicker or Harmonics measured at the Connection Point are within $\pm 5\%$ of values indicated in Sections 3.2.4 and 3.2.6.
- (b) The performance under disturbances test shall demonstrate that the Embedded Generating Unit is capable to withstand Voltage drops as indicated in Sections 4.5.4, 4.6.6 or 4.7.5, as applicable. The Embedded Generating Unit shall pass the test if its performance is equal or better than the prescriptions in the said Sections. The System Operator, the Distribution Utility and the Embedded Generation Company shall agree on the way that these tests should be carried out.

6.11.3 Test Requirements for Intermediate, Small and Micro Embedded Generating Units

6.11.3.1 Following tests shall be conducted, in accordance with the agreed procedures and standards, to confirm the compliance of Intermediate, Small and Micro Embedded Generating Units:

- (a) The Reactive Power test shall demonstrate that the Intermediate, Small or Micro Embedded Generating Plant can be connected to the Distribution System, generating Active Power and interchanging Reactive Power within the limits established in Sections 4.8.3 or 4.9.3, as applicable. The Embedded Generating Plant shall pass the test if the

Reactive Power interchanged lies between Power Factor 98% leading and 98% lagging.

- (b) The Protections Tests shall demonstrate that all the protections installed, in accordance with Section 4.9.5 perform with the required speed and selectivity settings as established in such Section. It shall also demonstrate that the Embedded Generating Plant disconnects from the Distribution System in case of Loss of Mains.
 - (c) The reconnection timing test (blocking test) shall demonstrate that, after the Loss of Mains, the Embedded Generating Plant remains blocked and it does not automatically reconnects to the network until the system is energized for at least 10 minutes, as indicated in Subsection 4.9.5.4
 - (d) The Synchronization Test shall demonstrate that the Embedded Generating Plant is capable of automatically synchronizing with the Distribution System within the parameters indicated in Subsection 4.9.5.3; and
 - (e) In case of Intermediate Embedded Generation Company, which have been required by the Distribution Utility to install a SCADA and communications facility, a communications tests shall demonstrate that the Embedded Generating Plant is capable of sending to the Distribution Utility the signals indicated in the Connection Agreement or Amended Connection Agreement.
- 6.11.3.2 Additional tests can be performed for Intermediate, Small and Micro Embedded Generating Units in cases that, based on an analysis of one or more network incidents or claims, the Distribution Utility has grounds to consider the performance of the Embedded Generating Plant is not complying with the prescriptions stated in the Philippine Distribution Code.
- 6.11.3.3 All tests shall be recorded and witnessed by the authorized representatives of the Distribution Utility, Embedded Generation Company, and/or User.
- 6.11.3.4 If an Intermediate, Small or Micro Embedded Generating Unit fails the test, the Embedded Generation Company or the User, as it corresponds, shall correct the deficiency within an agreed period to attain the relevant performance requirements for that Generating Unit.
- 6.11.3.5 If a dispute arises relating to the failure of an Embedded Generating Unit to pass a given test, the Distribution Utility, the Embedded Generation Company, and/or User shall seek to resolve the dispute among themselves. If the dispute cannot be resolved, one of the parties may submit the issue to the DMC.
- 6.11.3.6 The Embedded Generation Company and End-User using Small or Micro Embedded Generating Plant shall make available upon request by the Distribution Utility, a verification test report confirming that the specific Small or Micro Embedded Generation Plant model has been tested to satisfy the requirements of the Philippine Distribution Code. The report shall detail the model of the Embedded Generating Unit tested, the test

conditions and results recorded. All of these details shall be included on a test sheet.

6.11.3.7 Intermediate, Small or Micro Embedded Generating Plant shall pass, at least, the following Type Tests:

- (a) Harmonic Test;
- (b) Flicker Test;
- (c) DC Injection Test;
- (d) Protection Tests;
 - (1) Over-frequency;
 - (2) Under-frequency;
 - (3) Over and Under Voltage; and
 - (4) Anti-Islanding.
- (e) Reconnection Timer Test;
- (f) Fault Level Contribution Test; and
- (g) Self-Monitoring Test.

6.12 SITE AND EQUIPMENT IDENTIFICATION

6.12.1 Site and Equipment Identification Requirements

6.12.1.1 The Distribution Utility shall develop and establish a standard system for Site and Equipment Identification to be used in identifying any Site or Equipment in all Electrical Diagrams, Connection Point Drawings, distribution operation instructions, notices, and other documents.

6.12.1.2 The identification for the Site shall include and be unique for each substation and switchyard where a Connection Point is located.

6.12.1.3 The identification for Equipment shall be unique for each Transformer, distribution line, bus, Circuit Breaker, disconnect switch, Grounding switch, capacitor bank, reactor, lightning arrester, CCPD, and other MV and HV Equipment at the Connection Point.

6.12.2 Site and Equipment Identification Label

6.12.2.1 The Distribution Utility shall develop and establish a standard labelling system, which specifies the dimension, sizes of characters, and colors of labels, to identify the Sites and Equipment.

6.12.2.2 The Distribution Utility or the User shall be responsible for the provision and installation of a clear and unambiguous label showing the Site and Equipment Identification at their respective System.

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CHAPTER 7

DISTRIBUTION REVENUE METERING REQUIREMENTS

7.1 PURPOSE AND SCOPE

7.1.1 Purpose

- (a) To establish the requirements for metering the Active and Reactive Energy and Demand input to and/or output from the Distribution System;
- (b) To ensure appropriate procedures for providing Metering Data for billing and settlement.

7.1.2 Scope of Application

This Chapter applies to all Distribution System participants including:

- (a) Distribution Utilities;
- (b) Metering Service Providers;
- (c) Other Distribution Utilities connected to the Distribution System;
- (d) Embedded Generation Companies;
- (e) Large Customers; and
- (f) Other Users receiving unbundled services.

7.2 METERING REQUIREMENTS

7.2.1 Metering Equipment

The Metering Equipment shall consist of:

- (a) Revenue Meters;
- (b) Instrument Transformers, as may be applicable;
- (c) All interconnecting cables, wires, and associated devices, and protection, i.e., test block or switch, loading resistors, meter cubicle, security seals, etc.; and
- (d) Optional: Integrating pulse Recorder, time source, and backup battery.

7.2.2 Metering Point Location

7.2.2.1 The Metering Point shall be located at the Connection Point, unless the installation of the Metering Equipment is physically difficult, uneconomical or not practical.

7.2.2.2 If the Metering Point cannot be located in the Connection Point for justifiable reasons, Meters may be located in other locations or in accordance with relevant ERC issuances or guidelines.

7.2.2.3 If the Metering Point is not located at the Connection Point, an agreed procedure shall be established to account for the Energy loss between the Connection Point and Metering Point.

7.2.3 Metering Responsibility

7.2.3.1 The Distribution Utility or the MSP shall:

- (a) Be responsible for the design, installation, operation and maintenance of the metering System and the Component parts to ensure the integrity and accuracy of the metering System.
- (b) Ensure that the Metering Equipment is provided, installed, operated, maintained and tested in accordance with this Chapter. The supply and installation of the Metering Equipment shall be agreed upon by both parties in the Connection Agreement or Amended Connection Agreement.
- (c) Be responsible to provide and install all Metering Equipment at a location specified by the Distribution Utility.
- (d) Ensure that the Metering Equipment operates within the acceptable standard at all times and meets all technical requirements and standards set forth in this Chapter.
- (e) Read, retrieve, validate and deliver the Meter Data for billing and/or settlement, as maybe required.
- (f) Maintain records of tests and readings of the Metering Equipment.
- (g) Make arrangements to seal or secure all Metering Equipment, data collection Equipment and associated communication Equipment.

7.2.3.2 The Distribution Utility or the MSP and User shall also ensure that the requirements of this Chapter regarding access to Metering Equipment by other authorized parties are complied with.

7.2.3.3 The responsibilities for the supply of Metering Equipment and other obligations relative to the revenue metering facilities shall be in accordance with the agreements made between the User of the Distribution System and its Distribution Utility or the MSP.

7.2.4 Active Energy and Demand Metering

7.2.4.1 Metering shall be required at any Connection Point where Active Energy and Demand input to and/or output from the Distribution System by any User have to be measured.

7.2.4.2 Active and Demand metering shall be provided for each User at each Connection Point and shall be accessible for inspection and reading.

7.2.5 Reactive Energy and Demand Metering

7.2.5.1 This is a requirement at all Connection Points in which an input and/or output Connection Agreement exists between Distribution Utility and any User wherein the User has an input and/or output Reactive Energy and Reactive Power.

7.2.5.2 The Reactive Energy and Demand metering, when required, shall be provided to measure the input and/or output from the Distribution System. It shall measure all quadrants in which Reactive Power flow is possible.

7.2.6 Requirements for Instrument Transformers

7.2.6.1 The Voltage Transformers shall be compliant to the latest version of IEC 60044-2 or ANSI C57.13 Standard, with the following qualifications:

- (a) The Accuracy Class shall be as a minimum, 0.3 (ANSI) or 0.2 (IEC);
- (b) The voltage ratio shall be selected such that the operation at the minimum or maximum sustained secondary Voltage shall not affect Meter accuracy or Meter function;
- (c) A Type Test Report from the Manufacturer that documents compliance of the Voltage Transformers to the IEC 60044-2 or ANSI C57.13 Standard, to which the Voltage Transformers are designed and manufactured, shall be on file with the Distribution Utility or the MSP. The Type Test will only be required for samples of each new model.

7.2.6.2 The Current Transformers shall be compliant to the latest version of IEC 60044-1 or ANSI C57.13 Standard, with the following qualifications:

- (a) The Current Transformer ratio to be used shall be such that the expected minimum and maximum operating currents fall within the range where the ratio and phase accuracies are certified in accordance with the applicable ANSI or IEC Standard;
- (b) The Accuracy Class for Load metering service shall be 0.2 (IEC) or 0.3 (ANSI), or better. For Embedded Generating Plants' metering service, the Accuracy Class of the Current Transformers shall be such that the ratio and phase accuracies are certified by factory test reports based on governing standards where the Current Transformer is manufactured;
- (c) A Type Test Report from the Manufacturer that documents compliance of the Current Transformers to the IEC 60044-1 or ANSI C57.13 Standard, to which the Current Transformers are designed and manufactured, shall be on file with the Distribution Utility or the MSP. Type Test will only be required for samples of each new model.

7.2.7 Requirements for Distribution Revenue Meters

Technical requirements for distribution revenue Meters shall conform with the standards provided under Table 7-1 for Low Voltage Customers and Table 7-2 for MV/HV Customers.

TABLE 7-1
MINIMUM TECHNICAL REQUIREMENTS FOR DISTRIBUTION REVENUE METERS OF
LOW VOLTAGE CUSTOMERS

Service Type	Self-Contained Meter	Transformer Rated Meter
1-phase 2-wire	Form 1S and 1A	Form 3S/4S and 3A/4A
1-phase 3-wire	Form 2S and 2A	Form 4S and 4A
2-phase 3-wire	Form 12S/25S and 12A/25A	Form 5S/6S/9S/36S and 5A/6A/9A/36A
3-phase 3-wire	Form 12S/13S/25S and 12A/13A/25A	Form 5S/6S/9S/36S and 5A/6A/9A/36A
3-phase 4-wire, Wye	Form 14S/16S and 14A/16A	Form 6S/9S and 6A/9A
3-phase 4-wire, Delta	Form 15S/17S and 15A/17A	Form 8S and 8A

TABLE 7-2
MINIMUM TECHNICAL REQUIREMENTS FOR DISTRIBUTION REVENUE METERS OF
MEDIUM/HIGH VOLTAGE CUSTOMERS

Item	Revenue Meter
Accuracy Class	IEC 687 Class 0.2/ANSI 12.20 Class 0.3 or better
Voltage Rating	For self-contained - Correspond to the service voltage For instrument transformer rated - Correspond to the secondary Voltage rating of Voltage Transformers used
Current Rating	For self-contained – Typically ranging from 20 to 200 A For instrument transformer rated - Correspond to the secondary current rating of Current Transformers used (typically 1A or 5A)
Frequency	60 Hz
Measurement	Unidirectional active metering (delivered and two-quadrant reactive metering, if applicable) or, where bi-directional energy flows, bi-directional active metering
Interval Data (as applicable)	Programmable to 15-minute interval

Recording Billing Quantities (as applicable)	Display and record the applicable TOU energy and power parameters (kWh, kVARh if required)
Communication Capability (as applicable)	The Meter shall have one independent communication port in addition to the optical port.
Meter Cover	The Meter's internal Components shall be protected against the harmful elements of environment that may affect its measuring circuit and operation.

7.2.8 General Requirement for Grounding System

The installation shall be in accordance but not limited to the provisions of the following:

- (a) Latest edition of Philippine Electrical Code Article 2.5 Grounding and Bonding;
- (b) IEC or ANSI/IEEE C57.13-1983 IEEE Guide for Grounding of Instrument Transformer Secondary Circuits and Cases; and
- (c) IEEE Std. 80-2000 or IEEE Guide for Safety in AC Substation Grounding.

7.2.9 Meter Test Block or Switch

Test block or switch shall be installed inside the meter enclosure to allow the current and Voltage from each instrument transformer and each Meter to be individually determined. The installation shall also be in accordance but not limited to ANSI C12.8-1981 (R1997, R2002, R2012) or its equivalent standard.

7.2.10 Other Accessories

7.2.10.1 The Metering Equipment, for instrument rated Meter, shall be placed in a cubicle and shall be secured with seals and lock to prevent unauthorized interference with a provision for the register to be visible and accessible for monitoring.

7.2.10.2 All wiring from the instrument transformers' secondary terminal box to the Metering Equipment cubicle shall be placed in a rigid metal conduit or its equivalent.

7.2.10.3 The ERC (or its certified party/authorized representative) in the presence of the duly authorized representatives of the Distribution Utility or the MSP and the User shall seal Meters. All seals placed or removed on metering System shall be recorded and the record signed by both parties and the ERC or its duly authorized representative.

7.3 REQUIREMENTS FOR COMMISSIONING, TESTING AND MAINTENANCE OF METERING FACILITIES AND EQUIPMENT

7.3.1 Readiness of a Distribution System Metering Facility for Service

A Distribution System Metering Facility may only be declared as ready for revenue metering service when the following conditions are satisfied as certified by the ERC and the Distribution Utility or the MSP:

- (a) The instrument transformers are determined by inspection of their nameplates and Factory Test Reports, within the last 5 years, that they are compliant to the technical requirements under this Chapter and by actual test by ERC or by the Distribution Utility or the MSP as authorized by the ERC, and to have passed the acceptance criteria for accuracy class for a given burden and integrity in accordance with the IEC or ANSI Standard to which they have been manufactured.
- (b) The Revenue Meters are determined to be compliant with the technical requirements for meters under this Chapter, and by actual test by ERC or by the Distribution Utility or the MSP as authorized by the ERC.
- (c) The metering circuit has been installed, interconnected and tested as having passed the requirements of this Chapter.

7.3.2 Instrument Transformer Testing

- 7.3.2.1 No instrument transformer shall be installed or placed in service unless it has been tested and certified by the ERC.
- 7.3.2.2 Test on the Instrument Transformers shall be conducted by the authorized representatives of the Distribution Utility or the MSP in the presence of the User's authorized representative during the Test and Commissioning stage and as the need arises due to questions on accuracy.
- 7.3.2.3 The tests shall be carried out in accordance with the practices of the Distribution Utility or the MSP or based on an agreed equivalent international or guidelines set out by the ERC.
- 7.3.2.4 Prior to installation, the Instrument Transformers shall be tested for:
 - (a) Ratio and phase deviation at specified burden by Voltage and current injection to the primary windings.
 - (b) Burden Rating Verification.
- 7.3.2.5 Prior to commissioning to service, the instrument transformers shall be tested at the metering site or meter shop laboratory for:
 - (a) Insulation Integrity.
 - (b) Wiring Check.
 - (c) Nameplate Check.
- 7.3.2.6 The test methods and acceptance criteria shall be in accordance with the IEC or ANSI Standards to which the metering instrument transformers are designed and manufactured.
- 7.3.2.7 The on-site tests may only be performed by the Distribution Utility or the MSP or an entity authorized by the Distribution Utility or the MSP to perform such tests.

7.3.3 Meter Calibration and Testing

- 7.3.3.1 No Meter shall be installed or placed in service unless it has been tested, certified and sealed by the ERC.
- 7.3.3.2 Test and calibration of Meters shall be conducted by the ERC (or its authorized representative) in the presence of the authorized representatives of the Distribution Utility or the MSP, based on ERC rules and guidelines

for the Maintenance of Electric Meters of Distribution Utilities, as amended.

7.3.3.3 If both parties cannot agree on the accuracy of the Meter, only the ERC, shall act as arbiter.

7.3.4 Operation and Maintenance of Metering Facilities and Equipment

7.3.4.1 The Distribution Utility or the MSP shall maintain all Metering Equipment. Distribution Utility or the MSP shall keep all test results, Maintenance Programs, and sealing records for at least 5 years. The Equipment data and test records shall be furnished by the Distribution Utility or the MSP to the User upon request, subject to the Distribution Utility's policies in relation to record confidentiality.

7.3.4.2 The Metering Equipment at the Connection Point shall be operated and maintained in accordance with the latest ERC issued rules and procedures for the test and maintenance of electric Meters. The regular maintenance activities shall include as a minimum:

- (a) Periodic calibration and accuracy test of Meters, in accordance with the latest Rules for the In-Service Sampling Test requirement by the ERC based on ERC Rules and Procedures for the Test and Maintenance of Electric Meters of Distribution Utilities, as amended, and pre-installation test of instrument transformers; and
- (b) Periodic check of the Meter clock, if applicable, for deviations against the Philippine Standard Time.

7.3.4.3 Any reported Metering Equipment malfunction or failure or Metering Data defects shall be verified immediately by the Distribution Utility or the MSP. The correction or adjustment of meter data to address any confirmed Metering Equipment failure or malfunction shall be submitted by the Distribution Utility or the MSP within the billing period, or in accordance with prescribed timelines under the Distribution Utility's billing manual, or agreements with Embedded Generation Companies/Energy Suppliers. However, if the metering failure or malfunction is confirmed near the end of the billing period, any correction or adjustment of Meter data may be submitted by the Distribution Utility or the MSP in the immediately succeeding billing period.

7.3.4.4 A Metering Equipment that has failed in an accuracy test or malfunctioned shall be immediately replaced and restored to the prescribed configuration and shall be undertaken by the Distribution Utility or the MSP.

7.3.5 Traceability of Metering Standard

The Distribution Utility or the MSP shall ensure that all Equipment used in the measurement of Meter accuracy or in the establishment of test condition for the determination of Meter accuracy shall be calibrated and traceable to the National Institute of Standards or to any reputable international standard body. The traceability shall be carried out in accordance with the guidelines set by the ERC.

7.4 METER READING AND METERING DATA

7.4.1 Requirements for Metering Data

7.4.1.1 The type and format of Metering Data shall be in accordance with the requirements of the billing and settlement systems of the Distribution Utilities and Embedded Generation Companies that sell Energy to Customers through the Distribution Systems utilizing the Distribution System revenue metering facilities.

7.4.1.2 Meter reading and recording shall be done by the authorized representative of the Distribution Utility or the MSP on the date stipulated in a separate agreement.

7.4.2 Meter Data Collection and Delivery

Recorded meter data consisting of billing parameters shall be collected/retrieved by the Distribution Utility or the MSP from each meter by processes that assure the integrity and security of the retrieved Meter data. The retrieved meter data shall be delivered by the Distribution Utility or the MSP to:

- (a) The Distribution Utility's billing system: in accordance with its billing procedures and the Distribution Services and Open Access Rules (DSOAR).
- (b) Load Customers: in accordance with the DSOAR and agreements.
- (c) Other authorized Meter data users: in accordance with applicable rules and agreements.

7.4.3 Meter Register Reading

Meter register readings may be used to validate the integrity of Load Profile meter data, and as a reference in the estimation of un-recorded energy in the Load Profile meter data. If on-site meter register reading is performed for this purpose by the Distribution Utility or the MSP, it shall be witnessed by authorized representatives of the User of the Distribution System whose energy consumption or generation is metered.

7.4.4 Validation and Substitution of Metering Data

7.4.4.1 The Distribution Utility or the MSP shall be responsible for the validation and substitution of Metering Data on its System.

7.4.4.2 Metering data validation shall be performed in accordance with established methods, processes and criteria approved by the ERC. The validation shall confirm the integrity of Meter data, which include but not limited to:

- (a) Missing interval quantities;
- (b) Zero values due to power Outages;
- (c) Values outside established ranges;
- (d) Changes in values outside set limits;
- (e) Invalid power flow; and
- (f) Meter date and time deviations.

7.4.4.3 In principle, check-Metering Data if available, shall be used to validate the Metering Data provided that the check-Metering Equipment conforms to the accuracy requirements set forth in this Chapter.

7.4.4.4 If a check meter is not available or the Metering Data is missing, then a substitute value shall be prepared by the Distribution Utility or the MSP using the data validation and substitution method approved by the ERC.

7.4.5 Storage and Availability of Metering Data

7.4.5.1 The Distribution Utility or the MSP shall maintain both the “as metered” and the “as corrected” meter data in separate, controlled data storage systems for a minimum duration of 5 years, to be made available to authorized parties for the purpose of serving as reference in settling disputes and other authorized purposes. No alteration to the Metering Data stored in the database shall be permitted.

7.4.5.2 Records that document meter data corrections shall likewise be maintained by the Distribution Utility or the MSP and entities that are users or affected by the meter data corrections.

7.4.6 Persons or Entities Authorized to Receive Metering Data

Metering Data shall be treated as confidential information and can only be made available to authorized parties, as follows:

- (a) The Distribution Utility or the MSP, in accordance with its billing and settlement requirements.
- (b) Embedded Generation Companies and Energy Suppliers, for Metering Points of their respective Customers.
- (c) The User of the Distribution System, for Metering Points of its Connection Points to the Distribution System.
- (d) The ERC and/or DMC, in accordance with its mandates.
- (e) Other parties upon request and approval of the Distribution Utility or the MSP.

7.4.7 Security of Metering Facilities, Equipment and Data

7.4.7.1 The metering facility shall be secured from unauthorized physical access and activities that can lead to inaccurate registration or recording of the metered electricity.

7.4.7.2 The metering facility shall be provided with metal security enclosure, or other applicable material, as well as locks (when applicable) to the Meter security enclosures, and seals at all access points to the Metering Equipment terminals and interconnecting electrical cables. The Distribution Utility or the MSP shall provide the security locks (when applicable) and/or seals and periodically inspect the integrity of the same.

7.4.7.3 The User of the Distribution System shall properly secure the metering facilities that are located within its premises.

7.4.7.4 Any observed breach of security of the metering facility, such as unauthorized opening of the padlocks and seals shall be immediately

reported to the Distribution Utility or the MSP, and the User of the Distribution System by the party that discovers the security breach.

7.4.7.5 The Distribution Utility or the MSP shall investigate any reported breach of security to determine its effect on the Metering Equipment and the metered quantities of Energy and Demand; and report its findings to its Management and the Distribution Utility or the MSP, the concerned User of the Distribution System, and if required, the ERC.

7.4.7.6 The Distribution Utility or the MSP shall calculate and submit a recommended correction or adjustment to the metered quantities that are found to be in error due to the breach of security. In cases of disagreements, the ERC shall resolve the same in accordance with existing laws, rules and regulations.

7.4.7.7 The Distribution Utility or the MSP and all other Parties that are provided with revenue Metering Data are required to maintain the confidentiality of such Metering Data.

CHAPTER 8

PHILIPPINE DISTRIBUTION CODE TRANSITORY PROVISIONS

8.1 PURPOSE

To establish procedures which in some cases may allow permanent exemption from Philippine Distribution Code requirements.

8.2 COMPLIANCE WITH THE PHILIPPINE DISTRIBUTION CODE 2017 EDITION

8.2.1 Compliance of Distribution Utilities and Users

- 8.2.1.1 All Distribution Utilities, Embedded Generation Companies, Metering Service Providers and other Users shall comply with all the prescribed technical specifications, performance standards and other requirements of the PDC 2017 Edition and shall submit to the ERC, through the DMC, a Compliance Report to the PDC 2017 Edition, according to the requirements set forth in the Philippine Distribution Code and in the ERC Resolution No. 13, Series of 2011, adopting the Distribution Management Committee Rules to Govern the Monitoring of Compliance of Distribution Utilities to the Philippine Distribution Code and future amendments thereto. The Compliance Report also shall include all approved requests for Derogations.
- 8.2.1.2 All Embedded Generation Companies shall be required to fully comply upon the approval and renewal of their Certificate of Compliance (COC).
- 8.2.1.3 All Distribution Utilities that are not yet compliant to the PDC 2017 Edition, shall be required to fully comply upon the application of their next Regulatory Reset.
- 8.2.1.4 All Metering Service Providers that are not yet fully compliant to the PDC 2017 Edition, shall be required to fully comply upon renewal of their license/registration with the ERC.
- 8.2.1.5 All Metering Service Providers shall correct within 1 year Metering Points that do not comply with Chapter 7 of the PDC 2017 Edition.

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APPENDIX A

FINANCIAL CAPABILITY STANDARDS FOR DISTRIBUTION AND SUPPLY

1.1 PURPOSE AND SCOPE

1.1.1 Purpose

- (a) To specify the financial capability standards for Distributors and Suppliers;
- (a) To safeguard against the risk of financial non-performance;
- (b) To ensure the affordability of electric power supply while maintaining the required quality and Reliability; and
- (c) To protect the public interest.

1.1.2 Scope of Application

This Appendix applies to all Users of the Distribution System including:

- (a) Distribution Utilities; and
- (b) Suppliers.

1.2 DEFINITIONS

The following words and phrases shall, unless more particularly defined in an Article, Section, or Subsection of this Appendix, have the following meanings:

Average Collection Period. The ratio of average receivables to daily sales.

Average Receivables. The average of the accounts receivable at the beginning and end of the period.

Average Total Assets. The average of the assets at the beginning and end of the period.

Daily Sales. Total annual sales divided by 365 days.

Debt Ratio. The ratio of total liabilities to total assets.

Financial Efficiency Ratio. A financial indicator that measures the productivity in the entity's use of its assets.

Interest Cover. The ratio of earnings before interest and taxes plus depreciation to interest.

Leverage Ratio. A financial indicator that measures the degree of indebtedness of an entity.

Liquidity Ratio. A financial indicator that measures the ability of an entity to satisfy its short-term obligations as they become due.

Net Profit Margin. The ratio of net profits after taxes to sales.

Profitability Ratio. A financial indicator that measure the entity's return on its investments.

Quick Ratio. The ratio of current assets less inventory to current liabilities.

Return on Assets (ROA). The ratio of net profits after taxes to average total assets.

1.3 FINANCIAL STANDARDS FOR DISTRIBUTION UTILITIES

1.3.1 Financial Ratios

1.3.1.1 The following Financial Ratios shall be used to evaluate the Financial Capability of Distribution Utilities:

- (a) Leverage Ratios;
- (b) Liquidity Ratios;
- (c) Efficiency Ratios; and
- (d) Profitability Ratios.

1.3.2 Leverage Ratios

1.3.2.1 The Leverage Ratios for the Distribution Utility shall include the following:

- (a) Debt Ratio;
- (b) Debt-equity ratio; and
- (c) Interest Cover.

1.3.2.2 The Debt Ratio shall measure the degree of indebtedness or financial leverage of the Distribution Utility. The Debt Ratio shall be calculated as the ratio of Total Liabilities to Total Assets.

1.3.2.3 The Debt Ratio shall be used to measure the proportion of assets financed by creditors. The risk addressed by the Debt Ratio is the possibility that the Distribution Utility cannot pay off interest and principal.

1.3.2.4 The Debt Ratio can also be calculated as the ratio of Long-Term Debt plus Value of Leases to Long-Term Debt plus Value of Leases plus Equity. Equity is the sum of Outstanding Capital Stock, Retained Earnings, and Revaluation Increment.

1.3.2.5 The Debt-Equity Ratio shall indicate the relationship between long-term funds provided by creditors and those provided by the Distribution Utility. The Debt-Equity Ratio shall be calculated as the ratio of the sum of Long-Term Debt plus Value of Leases to Equity. The Equity shall be the sum of Outstanding Capital Stock, retained earnings, and revaluation increment.

1.3.2.6 The Debt-Equity Ratio shall be used to compare the financial commitments of creditors relative to those of the Distribution Utility.

1.3.2.7 The Debt-Equity Ratio shall be used as a measure of the degree of financial leverage of the Distribution Utility.

1.3.2.8 The Interest Cover shall measure the ability of the Distribution Utility to service its debts. The Interest Cover shall be computed as the ratio of Earnings Before Interest and Taxes (EBIT) plus depreciation to interest plus Principal Payments.

1.3.2.9 The Interest Cover shall also be used as a measure of financial leverage for the Distribution Utility that focuses on the extent to which contractual interest and principal payments are covered by Earnings Before Interest and Taxes plus Depreciation. The Interest Cover is

identical to Debt Service Capability Ratio because principal payments due during the year are included in the denominator of the ratio.

1.3.3 Liquidity Ratios

1.3.3.1 Liquidity Ratios shall include the following:

- (a) Financial Current Ratio; and
- (b) Quick Ratio.

1.3.3.2 The Financial Current Ratio shall measure the ability of the Distribution Utility to meet short-term obligations. The Financial Current Ratio shall be calculated as the ratio of Current Assets to Current Liabilities. The Current Assets shall consist of cash and assets that can readily be turned into cash by the Distribution Utility. The Current Liabilities shall consist of payments that the Distribution Utility is expected to make in the near future.

1.3.3.3 The Financial Current Ratio shall be used as a measure of the margin of liquidity of the Distribution Utility.

1.3.3.4 The Quick Ratio shall measure the ability of the Distribution Utility to satisfy its short-term obligations as they become due. The Quick Ratio shall be calculated as the ratio of the sum of Cash, Marketable Securities, and Receivables to the Current Liabilities.

1.3.3.5 The Quick Ratio shall be used to measure the safety margin for the payment of current debt of the Distribution Utility if there is shrinkage in the value of cash and receivables. It measures the ease with which the Distribution Utility can pay its bills.

1.3.4 Financial Efficiency Ratios

1.3.4.1 Financial Efficiency Ratios shall include the following:

- (a) Sales-to-Assets Ratio; and
- (b) Average Collection Period.

1.3.4.2 The Sales-to-Assets Ratio shall measure the efficiency with which the Distribution Utility uses all its assets to generate sales. The Sales-to-Assets Ratio shall be calculated as the ratio of Sales to Average Total Assets. The Average Total Assets shall be determined using the average of the assets at the beginning and end of the year. The higher the Sales-to-Assets Ratio, the more efficiently the assets of the Distribution Utility have been used.

1.3.4.3 The Average Collection Period (ACP) shall measure how quickly Customers pay their bills to the Distribution Utility. The Average Collection Period shall be calculated as the ratio of Average Receivables to Daily Sales. The Average Receivables shall be determined using the average of the receivables at the beginning and end of the year. The Daily Sales shall be computed by dividing Sales by 365 days.

1.3.4.4 The Average Collection Period shall be used to evaluate the credit and collection policies of the Distribution Utility.

1.3.4.5 Two computations of the Average Collection Period shall be made:

- (a) ACP with government accounts and accounts under litigation; and

(b) ACP without government accounts and accounts under litigation.

1.3.5 Profitability Ratios

1.3.5.1 Profitability Ratios shall include the following:

- (a) Net Profit Margin; and
- (b) Return on Assets.

1.3.5.2 The Net Profit Margin shall measure the productivity of sales effort. The Net Profit Margin shall be calculated as the ratio of Net Profits After Taxes to Sales. The Net Profits After Taxes shall be computed as Earnings Before Interest and Taxes minus Tax (EBIT – Tax). The Average Total Assets shall be computed as the average of the assets at the beginning and end of the year.

1.3.5.3 The Net Profit Margin shall be used to measure the percentage of each peso of sales of the Distribution Utility that remains after all costs and expenses have been deducted.

1.3.5.4 The Return on Assets (ROA) shall measure the overall effectiveness of the Distribution Utility in generating profits from its available assets. The Return on Assets shall be calculated as the ratio of Earnings Before Interest and Taxes minus Tax (EBIT- Tax) to the Average Total Assets. The Average Total Assets shall be computed as the average of the assets at the beginning and end of the year.

1.3.5.5 The Return on Assets shall be used to measure the overall effectiveness of the Distribution Utility in generating profits from their available assets.

1.3.6 Submission and Evaluation

1.3.6.1 The Distribution Utility shall submit to the ERC true copies of audited balance sheet and financial statement for the preceding year on or before May 15 of the current year.

1.3.6.2 The Distribution Utility shall submit to the ERC a profile of customers, indicating the average power consumption for each class of customers for the preceding year. This requirement is due on or before May 15 of the current year.

1.3.6.3 Failure to submit to the ERC the requirements shall serve as grounds for the imposition of appropriate sanctions, fines, and/or penalties.

1.3.6.4 All submissions shall be certified under oath by a duly authorized officer.

1.4 FINANCIAL STANDARDS FOR SUPPLIERS

1.4.1 Prudential Requirements

The following Prudential Requirements shall be met by Suppliers, marketers, brokers, aggregators, or other third-party entities in order to have a license from ERC to sell electricity at retail:

- (a) Financial Requirements;
- (b) Credit Standards;

- (c) Financial Standards for Customer Protection;
- (d) Certification Standards;
- (e) Financial Standards for Billing, Collection, and Profitability; and
- (f) Organizational and Managerial Resource Requirements.

1.4.2 Financial Requirements

- 1.4.2.1 An applicant for a license to sell electricity at retail shall submit to the ERC true copies of audited balance sheet, cash flow, and income statement for the two most recent 12-month periods. The balance sheet, income statements, and cash flow statements shall be for the applicant, and not for a parent corporation (if one exists).
- 1.4.2.2 If the applicant has not been in existence for at least two 12-month periods, it shall provide true copies of audited balance sheet, income statements, and cash flow statements for the life of the business.
- 1.4.2.3 If a parent or other company has undertaken to ensure the financial integrity of the applicant, the applicant shall submit the parent's or other company's balance sheet, income statements, and cash flow statements together with the applicant's own balance sheet, income statements, and cash flow statements.

1.4.3 Credit Standards

An applicant shall satisfy any of the following methods to demonstrate that it has the financial capability required for credit quality:

- (a) Investment grade credit rating by a reputable credit bureau;
- (b) Assets in excess of liabilities (minimum value to be determined by the ERC after public consultation);
- (c) Unused cash resources to meet the applicant's proposed certification level (the level of unused cash resources to be determined by the ERC based on the applicant's expected monthly billings); or
- (d) The applicant can provide proof of its creditworthiness through the certification of companies (including Distribution Utilities), which have imposed credit terms on the applicant.

1.4.4 Financial Standards for Customer Protection

- 1.4.4.1 If the applicant plans to collect funds, including deposits or advances, from customers prior to providing services, the applicant must provide a minimum security deposit in the form of either a cashier's check or a financial guarantee bond to be posted with the ERC to cover the applicant's minimum exposure (the amount of deposit shall be determined by the ERC after public consultation).
- 1.4.4.2 The amount of the security deposit shall be based upon sales value that the applicant will collect by way of deposits or advance payments.
- 1.4.4.3 The amount of the security deposit shall be sufficient to cover one-half of the expected sales (price per kilowatt-hour times number of kilowatt-hours) that the applicant projects it will sell to customers over a 12-month period. If there is a big discrepancy between actual sales and expected

sales over a two-year period, the actual sales on the preceding year shall be used as the basis for the computation of the security deposit in the current year.

1.4.4.4 The amount of the security deposit shall be sufficient to provide adequate recourse for customers in the event of fraud or non-performance by the applicant.

1.4.4.5 The applicant shall designate the geographic area (or customer class) it intends to serve.

1.4.4.6 The ERC shall adopt an annual fee to be charged to all applicants on an annual basis (the amount to be determined by the ERC and will change from time to time).

1.4.4.7 The financial standards for customer protection apply primarily to all the applicants' funds, including deposits or advances, from customers prior to providing services.

1.4.5 Certification Standards

1.4.5.1 Prior to the grant of a license, the ERC may require that applicants, who do not plan to collect funds or advanced deposits prior to providing services, to procure a bond or insurance coverage in an amount sufficient to protect customers in the event of default or non-performance by the applicant.

1.4.5.2 The amount of the bond or insurance shall be based on the number of customers expected to be served and the number of kilowatt-hours of electricity the applicant expects to supply. Incentives (in terms of reduced deposit requirements) may be given to applicants who have shown outstanding customer service performance, and who have consistently and accurately estimated expected sales.

1.4.5.3 The applicant shall designate the geographic area (or customer class) it intends to serve.

1.4.5.4 The ERC shall adopt an annual fee to be charged to all applicants on an annual basis (the amount shall be determined by the ERC and will change from time to time).

1.4.5.5 Certifications standards apply primarily to applicants who do not plan to collect funds or advanced deposits prior to providing services.

1.4.6 Financial Standards for Billing, Collection, and Profitability

1.4.6.1 The following Financial Ratios shall be used to assess the capability of Suppliers to bill, collect from its customers, and earn a satisfactory rate of return on its investment.

(a) Leverage Ratios:

(1) Debt Ratio;

(2) Debt-Equity Ratio; and

(3) Interest Cover;

(b) Liquidity Ratios:

(1) Current Ratio;

- (2) Quick Ratio;
 - (c) Efficiency Ratios:
 - (1) Sales-to-Assets Ratio; and
 - (2) Average Collection Period;
 - (d) Profitability Ratios:
 - (1) Net Profit Margin; and
 - (2) Return on Assets.
- 1.4.6.2 The Debt Ratio shall measure the degree of indebtedness or financial leverage of the Suppliers. The Debt Ratio shall be calculated as the ratio of Total Liabilities to Total Assets. The Debt Ratio shall be used to measure the proportion of assets financed by creditors. The risk addressed by the Debt Ratio is the possibility that the Supplier cannot pay off interest and principal.
- 1.4.6.3 The Debt-Equity Ratio shall indicate the relationship between long-term funds provided by creditors and those provided by the Supplier. The Debt-Equity Ratio shall be calculated as the ratio of Long-Term Debt plus Value of Leases to Equity.
- 1.4.6.4 The Interest Cover shall measure the ability of the Supplier to service its debts. The Interest Cover shall be computed as the ratio of Earnings Before Interest and Taxes (EBIT) plus Depreciation to Interest plus Principal Payments. The Interest Cover is identical to Debt Service Capability Ratio because principal payments due during the year are included in the denominator of the ratio.
- 1.4.6.5 The Financial Current Ratio shall measure the ability of the Supplier to meet short-term obligations. The Financial Current Ratio shall be calculated as the ratio of Current Assets to Current Liabilities. The Current Assets shall consist of cash and assets that can readily be turned into cash by the Supplier. The Current Liabilities shall consist of payments that the Supplier is expected to make in the near future.
- 1.4.6.6 The Quick Ratio shall measure the ability of the Supplier to satisfy its short-term obligations as they become due; Quick Ratio shall be calculated as the ratio of the sum of Cash, Marketable Securities, and Receivables to the Current Liabilities. The Quick Ratio shall be used to measure the safety margin for the payment of current debt of the Supplier if there is shrinkage in the value of cash and receivables.
- 1.4.6.7 The Sales-to-Assets Ratio shall measure the efficiency with which the Supplier uses all its assets to generate sales. The Sales-to-Assets Ratio shall be calculated as the ratio of Sales to Average Total Assets. The Average Total Assets shall be determined using the average of the assets at the beginning and end of the year.
- 1.4.6.8 The Average Collection Period shall measure how quickly customers pay their bills to the Supplier. The Average Collection Period shall be calculated as the ratio of Average Receivables to Daily Sales. The Average Receivables shall be determined using the average of the receivables at the beginning and end of the year. The Daily Sales shall be computed by

dividing Sales by 365 days. Average Collection Period shall be computed as:

- 1.4.6.9 Those with government accounts and accounts under litigation; and
- 1.4.6.10 Those without government accounts and without accounts under litigation.
- 1.4.6.11 The Net Profit Margin shall measure the productivity of sales effort. The Net Profit Margin shall be calculated as the ratio of Net Profits After Taxes to Sales. The Net Profits After Taxes shall be computed as Earnings Before Interest and Taxes minus Tax (EBIT – Tax).
- 1.4.6.12 The Return on Assets shall measure the overall effectiveness of the Supplier in generating profits from its available assets. The Return on Assets shall be calculated as the ratio of Earnings Before Interest and Taxes minus Tax (EBIT – Tax) to the Average Total Assets. The Average Total Assets shall be computed as the average of the assets at the beginning and end of the year.

1.4.7 Organizational and Managerial Resource Requirements

- 1.4.7.1 As a requisite for providing retail electric service, a Supplier shall have the technical resources to supply continuous electric service to Customers in its service area and the organizational and managerial ability, in accordance with its Customer contracts.
- 1.4.7.2 The applicant shall provide the following information:
 - (a) Capability to comply with all scheduling, operating, planning, reliability, Customer registration and settlement policies, rules, guidelines, and procedures established by the Transmission Network Provider and System Operator;
 - (b) Capability to comply with 24-hour coordination with control centers for scheduling changes, reserve implementation, curtailment orders, interruption plan and implementation, and telephone number, fax number, and address where its staff can be directly reached at all times;
 - (c) At least one officer or employee experienced in the retail electric industry, or a related industry;
 - (d) Adequate staffing and employee training to meet all service level commitments;
 - (e) A Customer Service Program that describes how the Supplier complies with the ERC's customer protection rules; and
 - (f) A disclosure of whether the applicant (officer, director, or principal) has been found liable for fraud, theft or larceny, deceit, or violations of any customer protection or deceptive trade laws in any country.

1.4.8 Submission and Evaluation

- 1.4.8.1 The Supplier shall submit to the ERC true copies of audited balance sheet, income statements, and cash flow statements for the two most recent 12 month periods or for the life of the business, whichever is applicable. These requirements shall be submitted by the applicant upon application for licensing and by the Supplier, on or before May 15 of the current year.

- 1.4.8.2 Within 60 days of complying with the credit standards, the applicant (or Supplier) shall file with the ERC a sworn affidavit that demonstrates compliance with this requirement. Such a demonstration of compliance shall include the provision, along with the affidavit, of independent third party documentation verifying the veracity of the information relied upon for compliance.
- 1.4.8.3 Within 60 days of complying with the financial standards for Customer protection, the applicant (or Supplier) shall file with the ERC a sworn affidavit that attests compliance with the minimum security deposit requirement. Such a demonstration of compliance shall be accompanied by documentation by the bank, insurance company, or any accredited financial intermediary verifying the integrity and validity of the financial instruments relied upon for compliance.
- 1.4.8.4 Within 60 days of complying with certification standards, the applicant (or Supplier) shall file with the ERC a sworn affidavit that attests compliance (including providing minimum security deposit if required). Such a demonstration of compliance shall be accompanied by documentation from an independent third party verifying the validity of the documents relied upon for compliance.
- 1.4.8.5 Within 60 days of complying with organizational and managerial resource requirements, the applicant (or Supplier) shall file with the ERC a sworn affidavit that attests compliance with this requirement.
- 1.4.8.6 The applicant shall inform the ERC of its proposed geographic service area.
- 1.4.8.7 The applicant shall inform the ERC the type of service agreement it entered with a Distribution Utility whose Franchise Area the applicant is planning to offer its services. Such an agreement shall include a provision of whether End-Users will be billed separately by the Supplier and Distribution Utility, or will instead receive a consolidated bill from either the Supplier or the Distribution Utility.
- 1.4.8.8 A Supplier shall submit to the ERC a profile of its customers, indicating the average power consumption for each type of customers for the preceding twelve months. This requirement shall be due on or before May 15 of the current year.
- 1.4.8.9 Failure to submit the requirements to the ERC, shall serve as grounds for the imposition of appropriate sanctions, fines, penalties, or adverse evaluation.
- 1.4.8.10 All submissions shall be certified under oath by a duly authorized officer.

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APPENDIX B
FORMULA

1.1 CUSTOMER AVERAGE INTERRUPTION DURATION INDEX (CAIDI)

$$CAIDI = \frac{\sum \text{Customer Interruption Duration}}{\text{Total Number of Customers Interrupted}}$$

To calculate the index,

$$CAIDI = \frac{\sum r_i N_i}{\sum N_i} = \frac{SAIDI}{SAIFI}$$

Where:

- r_i = Restoration Time for each Interruption Event
- N_i = Number of Interrupted Customers for each Sustained Interruption event during the reporting period

1.2 LONG TERM FLICKER SEVERITY

$$P_{lt} = \sqrt[3]{\sum_{i=1}^{12} \frac{P_{sti}^3}{12}}$$

1.3 MOMENTARY AVERAGE INTERRUPTION FREQUENCY INDEX (MAIFI)

$$MAIFI = \frac{\sum \text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}}$$

To calculate the index,

$$MAIFI = \frac{\sum IM_i N_{mi}}{N_T}$$

Where:

- IM_i = Number of Momentary Interruptions
- N_{mi} = Number of Interrupted Customers for each Momentary Interruption event during the reporting period

$N_T =$ Total Number of Customers Served for the Areas

1.4 SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI)

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

To calculate the index,

$$SAIDI = \frac{\sum r_i N_i}{N_T} = \frac{CMI}{N_T}$$

Where:

r_i = Restoration Time for each Interruption Event

N_i = Number of Interrupted Customers for each Sustained Interruption event during the reporting period

CMI = Customer Minutes Interrupted

$N_T =$ Total Number of Customers Served for the Areas

1.5 SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI)

$$SAIFI = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$$

To calculate the index,

$$SAIFI = \frac{\sum N_i}{N_T} = \frac{CI}{N_T}$$

Where:

N_i = Number of Interrupted Customers for each Sustained Interruption event during the reporting period

CI = Customers Interrupted

$N_T =$ Total Number of Customers Served for the Areas

1.6 TOTAL DEMAND DISTORTION (TDD)

$$TDD = \frac{\sqrt{\sum_{h=2}^{\infty} I_h^2}}{I_L} \times 100\%$$

Where,

I_L = maximum demand load current

I_h = r.m.s. value of the harmonic current of order h

h = harmonic order

1.7 TOTAL HARMONIC DISTORTION (THD)

$$THD = \frac{\sqrt{\sum_{h=2}^{\infty} Q_h^2}}{Q} \times 100\%$$

Where,

Q = r.m.s. value of the fundamental component; represents either current or voltage

Q_h = r.m.s. value of the harmonic component of order h

h = harmonic order

1.8 VOLTAGE UNBALANCE

$$\%LVUR = \frac{\text{maximum} \left| V_{an} - \frac{V_{an} + V_{bn} + V_{cn}}{3} \times V_{bn} - \frac{V_{an} + V_{bn} + V_{cn}}{3} \times V_{cn} - \frac{V_{an} + V_{bn} + V_{cn}}{3} \right|}{\frac{V_{an} + V_{bn} + V_{cn}}{3}} \times 100$$

Or simply,

Phase Voltage Unbalance Rate (PVUR)

$$\%PVUR = \frac{\text{maximum voltage deviation from average phase voltage}}{\text{average phase voltage}} \times 100$$

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APPENDIX C

SAMPLE COMPUTATION FOR INDICES

For illustration purposes without Major Event Days:

INTERRUPTION REPORTS

For the month of January , Year 2016

Distribution Utility: _____

District/Zone/or Load Center: _____

Number of Customers Served during the month: 234,567

Date	Town/City/Barangay or Subdivision Affected	Circuit No.	Start Time	Restored		Duration (min.)	No. of Cust. Affected	Interruption			
				Date	Time			Cause	Weather	Isolation Device	Equipment Failed
3-Jan-16	Town A	Ckt 1	3:49 PM	3-Jan-16	3:53 PM	4	582	009	104	201	304
5-Jan-16	Town A	Ckt 2	3:49 PM	5-Jan-16	3:50 PM	1	6005	009	104	201	304
11-Jan-16	Town A	Ckt 2	11:03 PM	11-Jan-16	11:08 PM	5	6005	009	104	201	304
15-Jan-16	Town C	Ckt 6	1:44 PM	15-Jan-16	1:46 PM	2	1284	011	104	201	313
16-Jan-16	Town B	Ckt 3	2:51 PM	16-Jan-16	5:01 PM	130	26498	009	104	201	304
16-Jan-16	Town C	Ckt 5	8:11 PM	16-Jan-16	8:38 PM	27	5012	010	104	201	313
24-Jan-16	Town B	Ckt 3	5:50 PM	24-Jan-16	6:00 PM	10	26498	009	104	201	304
27-Jan-16	Town B	Ckt 4	5:06 AM	27-Jan-16	5:12 AM	6	22388	011	104	201	313
27-Jan-16	Town C	Ckt 6	5:14 AM	27-Jan-16	5:22 AM	8	1284	011	104	201	313

$$SAIFI = \frac{(26.498 + 5.012 + 26.498 + 22.388 + 1.284)}{234.567} = 0.3482$$

$$SAIDI = \frac{[(130 + 10) \times 26.498] + (27 \times 5.012) + (6 \times 22.388) + (8 \times 1.284)}{234.567} = 17.0085$$

$$CAIDI = \frac{17.0085}{0.3482} = 48.8448$$

$$MAIFI = \frac{(582 + 6,005 + 6,005 + 1,284)}{234,567} = 0.0592$$