



Energy Regulatory Commission

PHILIPPINE DISTRIBUTION CODE

December 2001

FOREWORD

The Philippine Distribution Code establishes the basic rules, procedures, requirements, and standards that govern the operation, maintenance, and development of the electric Distribution Systems in the Philippines. The Distribution Code will be used with the Philippine Grid Code and the Market Rules of the Wholesale Electricity Spot Market to ensure the safe, reliable, and efficient operation of the total electric energy supply system in the Philippines.

Republic Act No. 9136, also known as the “*Electric Power Industry Reform Act of 2001*,” mandated the creation of the Energy Regulatory Commission (ERC). Section 43(b) of the Act provides that the ERC promulgate and enforce a National Grid Code and a Distribution Code which shall include, but not be limited to: (a) Performance Standards for TRANSCO O & M Concessionaire, Distributors, and Suppliers, and (b) Financial Capability Standards for the Generating Companies, the TRANSCO, Distributors, and Suppliers. The Act also mandates the ERC to enforce compliance with the Grid Code, the Distribution Code, and the Market Rules and to impose fines and penalties for any violation of their provisions.

The restructuring of the electric power industry will result in significant changes in Distribution System operation and management. The Act allows End-Users belonging to the contestable market to obtain power from Suppliers who are licensed by the ERC. Distributors must provide wheeling services to these End-Users. Distributors must also procure energy from the Wholesale Electricity Spot Market and through bilateral contracts to serve the remainder of the customers in their franchise area.

The Distribution Code defines the technical aspects of the working relationship between the Distributors and all Users of the Distribution System. Distributors must deliver electric energy to the Users at acceptable levels of power quality and customer service performance. On the other hand, the Users of the Distribution Systems must comply with certain rules and standards to avoid any adverse effect on the Distribution System.

The policies and decisions of the Distributor on matters involving the operation, maintenance, and development of the Distribution System will affect industry participants and the Users of the Distribution System. It is important, therefore, that all affected parties have a voice in making policies and decisions involving the operation, maintenance, and development of the Distribution System. The Distribution Code provides this mechanism through the Distribution Management Committee, which will relieve the Energy Regulatory Commission from the tedious task of monitoring the day-to-day operation of the Distribution Systems.

The Philippine Distribution Code (PDC) is organized into nine (9) Chapters. These are:

Chapter 1. Distribution Code General Conditions

Chapter 2. Distribution Management

Chapter 3. Performance Standards for Distribution and Supply

Chapter 4. Financial Capability Standards for Distribution and Supply

Chapter 5. Distribution Connection Requirements

Chapter 6. Distribution Planning

Chapter 7. Distribution Operations

Chapter 8. Distribution Revenue Metering Requirements

Chapter 9. Distribution Code Transitory Provisions

Chapter 1 of the PDC cites the legal and regulatory framework for the promulgation and enforcement of the Philippine Distribution Code. It also specifies the general provisions that apply to all the other Chapters of the Distribution Code and contains articles on definition of terms and abbreviations used in the Distribution Code.

Chapter 2 of the PDC specifies the guidelines for Distribution Management, the procedures for dispute resolution, the required operational reports, and the process for Distribution Code enforcement and revision.

Chapter 3 of the PDC specifies the performance standards for the distribution and supply of electricity to ensure power quality and the efficiency and reliability of the Distribution System. It also specifies the customer services that are necessary for the protection of the End-Users in both the captive and contestable markets. The safety standards for the protection of personnel in the work environment are also included in this Chapter.

Chapter 4 of the PDC specifies the financial capability standards in the distribution and supply sectors to safeguard against the risk of financial non-performance, ensure the affordability of electric power supply, and to protect the public interest.

Chapter 5 of the PDC specifies the procedures and requirements to be complied with by any User who is connected or seeking connection to a Distribution System and the minimum technical, design, and operational criteria that applies to Distributors.

Chapter 6 of the PDC specifies the technical criteria and procedures to be applied by a Distributor in planning the development or reinforcement of its Distribution System and to be taken into account by Users in planning the expansion of their own Systems.

Chapter 7 of the PDC establishes the rules and procedures to be followed by the Distributor and all Users of the Distribution System to ensure the safe, reliable, and secure operation of the Distribution System.

Chapter 8 of the PDC specifies the technical requirements pertaining to the measurement of electrical quantities associated with the supply of electricity and the procedures for providing metering data for billing and settlement.

Chapter 9 of the PDC specifies the rules and procedures pertaining to compliance with the provisions of the Distribution Code during the transition period from the existing industry structure to the new industry structure. The procedures for the grant of exemption from specific requirements of the Distribution Code are also addressed in this Chapter.

Republic of the Philippines

Energy Regulatory Commission

Pasig City, Metro Manila

Resolution No. 115

**ADOPTION OF THE PHILIPPINE GRID CODE AND THE
PHILIPPINE DISTRIBUTION CODE**

WHEREAS, the Congress of the Philippines enacted Republic Act No. 9136, also known as the *Electric Power Industry Reform Act of 2001*, to ordain reforms in the Electric Power Industry and to provide framework for the restructuring thereof, including the privatization of the assets of the National Power Corporation, the transition to the desired competitive electric power industry structure, and the definition of the roles and responsibilities of the various government agencies and private entities;

WHEREAS, the Act declared the policy objectives of the government in undertaking the reform of the electric power industry, which include among others:

- (a) To ensure quality, reliability, security, and affordability of the supply of electric power; and
- (b) To protect the public interest as it is affected by the rates and services of electric utilities and other providers of electric power;

WHEREAS, the Act mandated the creation of the Energy Regulatory Commission (ERC), an independent, quasi-judicial regulatory body that is tasked to promote competition, encourage market development, ensure customer choice, and penalize abuse of market power in the restructured electric power industry;

WHEREAS, the Act mandated the ERC to promulgate and enforce, in accordance with law, a National Grid Code and a Distribution Code;

WHEREAS, the Act mandated that the Grid Code and the Distribution Code shall include performance standards for the National Transmission Corporation (TRANSCO) and/or its operations and maintenance concessionaire, Distribution Utilities and Suppliers, and financial capability standards for the Generating Companies, the TRANSCO, Distribution Utilities, and Suppliers;

WHEREAS, the Grid Code shall provide for the rules, requirements, procedures, and standards that will ensure the safe, reliable, secured and efficient operation, maintenance, and development of the high-voltage backbone transmission system in the Philippines;

WHEREAS, the Distribution Code shall provide for the rules, requirements, procedures, and standards that will ensure the safe, reliable, secured and efficient operation, maintenance, and development of the distribution systems in the Philippines;

NOW, THEREFORE, by virtue of Republic Act No. 9136, the Commission RESOLVES, as it so hereby RESOLVES, to adopt the PHILIPPINE GRID CODE and the PHILIPPINE DISTRIBUTION CODE.

FURTHER, RESOLVED, that this Resolution and the Codes shall be effective on the 15th day following their publication in at least two (2) national papers of general circulation.

Fe B. Barin
Chairman

Mary Anne B. Colayco
Commissioner

Oliver B. Butalid
Commissioner

Carlos R. Alindada
Commissioner

Leticia V. Ibay
Commissioner

PHILIPPINE DISTRIBUTION CODE

TABLE OF CONTENTS

Chapter	Description	Page
	Foreword.....	i
	Adoption of the Philippine Grid Code and the Philippine Distribution Code	iii
1	Distribution Code General Conditions	1
1.1	Purpose and Scope	1
1.1.1	Purpose.....	1
1.1.2	Scope of Application.....	1
1.2	Authority and Applicability	1
1.2.1	Authority	1
1.2.2	Applicability	1
1.3	Enforcement and Suspension of Provisions.....	1
1.3.1	Enforcement	1
1.3.2	Suspension of Provisions	2
1.4	Data, Notices, and Confidentiality.....	2
1.4.1	Data and Notices	2
1.4.2	Confidentiality	2
1.5	Construction of References	2
1.5.1	References.....	2
1.5.2	Cross-References	2
1.5.3	Definitions.....	3
1.5.4	Foreword, Table of Contents, and Titles	3
1.5.5	Mandatory Provisions	3
1.5.6	Singularity and Plurality	3
1.5.7	Gender.....	3
1.5.8	“Include” and “Including”	3
1.5.9	“Written” and “In Writing”	3
1.5.10	Repealing Clause	3
1.6	Definitions.....	3
1.7	Abbreviations.....	18
2	Distribution Management	21
2.1	Purpose and Scope	21
2.1.1	Purpose.....	21
2.1.2	Scope of Application.....	21
2.2	Distribution Management Committee.....	21
2.2.1	Functions of the Distribution Management Committee.....	21
2.2.2	Membership of the DMC	22

2.2.3 Terms of Office of the DMC Members	22
2.2.4 DMC Support Staff and Operating Cost.....	23
2.2.5 DMC Rules and Procedures.....	23
2.3 Distribution Management Subcommittees.....	23
2.3.1 Distribution Technical Standards Subcommittee.....	23
2.3.2 Distribution Reliability and Protection Subcommittee	24
2.3.3 Distribution Tariff Framework Subcommittee	24
2.3.4 Distribution Metering and Settlements Subcommittee	24
2.3.5 Other Distribution Subcommittees	25
2.4 Distribution Code Dispute Resolution.....	25
2.4.1 Distribution Code Disputes.....	25
2.4.2 Distribution Code Dispute Resolution Process.....	25
2.4.3 Distribution Code Dispute Resolution Panel	25
2.4.4 Cost of Dispute Resolution	26
2.5 Distribution Code Enforcement and Revision Process.....	26
2.5.1 Enforcement Process.....	26
2.5.2 Fines and Penalties.....	26
2.5.3 Unforeseen Circumstances.....	27
2.5.4 Distribution Code Revision Process	27
2.6 Distribution Management Reports.....	27
2.6.1 Quarterly and Annual Reports	27
2.6.2 Significant Incident Reports	27
2.6.3 Special Reports	28
3 Performance Standards for Distribution and Supply	29
3.1 Purpose and Scope	29
3.1.1 Purpose.....	29
3.1.2 Scope of Application.....	29
3.2 Power Quality Standards for Distributors.....	29
3.2.1 Power Quality Problems	29
3.2.2 Frequency Variations	30
3.2.3 Voltage Variations	30
3.2.4 Harmonics	30
3.2.5 Voltage Unbalance.....	31
3.2.6 Flicker Severity.....	31
3.2.7 Transient Voltage Variations	31
3.3 Reliability Standards for Distributors	31
3.3.1 Criteria for Establishing Distribution Reliability Standards.....	31
3.3.2 Distribution Reliability Indices.....	32
3.3.3 Inclusions and Exclusions of Interruption Events	32
3.3.4 Submission of Distribution Reliability Reports and Performance Targets..	33
3.4 System Efficiency Standards for Distributors.....	33
3.4.1 System Loss Classifications.....	33
3.4.2 System Loss Cap.....	33
3.4.3 Power Factor at the Connection Point	33
3.5 Customer Service Standards for Distributors and Suppliers.....	34

3.5.1 Customer Service Standards	34
3.5.2 Measuring Customer Service Performance	34
3.5.3 Customer Service Standards for Distributors	34
3.5.4 Customer Service Standards for Suppliers	34
3.6 Safety Standards for Distribution Utilities and Suppliers.....	36
3.6.1 Adoption of PEC and OSHS.....	36
3.6.2 Measurement of Performance for Personnel Safety	37
3.6.3 Submission of Safety Records and Reports	37
4 Financial Capability Standards for Distribution and Supply	39
4.1 Purpose and Scope	39
4.1.1 Purpose.....	39
4.1.2 Scope of Application.....	39
4.2 Financial Standards for Distributors	39
4.2.1 Financial Ratios	39
4.2.2 Leverage Ratios	39
4.2.3 Liquidity Ratios	40
4.2.4 Financial Efficiency Ratios.....	41
4.2.5 Profitability Ratios	41
4.2.6 Submission and Evaluation.....	42
4.3 Financial Standards for Suppliers	42
4.3.1 Prudential Requirements.....	42
4.3.2 Financial Requirements	42
4.3.3 Credit Standards.....	43
4.3.4 Financial Standards for Customer Protection	43
4.3.5 Certification Standards.....	44
4.3.6 Financial Standards for Billing, Collection, and Profitability	44
4.3.7 Organizational and Managerial Resource Requirements.....	46
4.3.8 Submission and Evaluation.....	46
5 Distribution Connection Requirements	49
5.1 Purpose and Scope	49
5.1.1 Purpose.....	49
5.1.2 Scope of Application.....	49
5.2 Distribution Technical, Design, and Operational Criteria	49
5.2.1 Power Quality Standards.....	49
5.2.2 Frequency Variations.....	49
5.2.3 Voltage Variations	50
5.2.4 Power Factor	50
5.2.5 Harmonics	50
5.2.6 Voltage Unbalance	50
5.2.7 Flicker Severity.....	50
5.2.8 Transient Voltage Variations	51
5.2.9 Protection Arrangements	51
5.2.10 Equipment Short Circuit Rating.....	51
5.2.11 Grounding Requirements.....	51

5.2.12 Monitoring and Control Equipment Requirements.....	52
5.2.13 Equipment Standards	52
5.2.14 Maintenance Standards	52
5.3 Procedures for Distribution Connection or Modification	52
5.3.1 Connection Agreement	52
5.3.2 Amended Connection Agreement.....	53
5.3.3 Distribution Impact Studies	53
5.3.4 Application for Connection or Modification	53
5.3.5 Processing of Application.....	54
5.3.6 Submittals Prior to the Commissioning Date.....	54
5.3.7 Commissioning of Equipment and Physical Connection to the Distribution System.....	55
5.4 Requirements for Embedded Generators	55
5.4.1 Requirements Relating to the Connection Point.....	55
5.4.2 Embedded Generating Unit Power Output	56
5.4.3 Frequency Withstand Capability.....	56
5.4.4 Unbalance Loading Withstand Capability.....	56
5.4.5 Speed-Governing System.....	56
5.4.6 Excitation Control System	57
5.4.7 Black Start Capability	57
5.4.8 Fast Start Capability.....	57
5.4.9 Protection Arrangements	57
5.4.10 Transformer Connection and Grounding.....	58
5.5 Requirements for Distribution Users	58
5.5.1 Requirements Relating to the Connection Point.....	58
5.5.2 Protection Arrangements	58
5.5.3 Transformer Connection and Grounding.....	58
5.5.4 Underfrequency Relays for Automatic Load Dropping.....	58
5.6 Fixed Asset Boundary Document Requirements.....	59
5.6.1 Fixed Asset Boundary Document	59
5.6.2 Accountable Managers.....	60
5.6.3 Preparation of Fixed Asset Boundary Document	60
5.6.4 Signing and Distribution of Fixed Asset Boundary Document	61
5.6.5 Modifications of an Existing Fixed Asset Boundary Document	61
5.7 Electrical Diagram Requirements	61
5.7.1 Responsibilities of the Distributor and Users	61
5.7.2 Preparation of Electrical Diagrams.....	62
5.7.3 Changes to Electrical Diagrams.....	62
5.7.4 Validity of Electrical Diagrams	63
5.8 Connection Point Drawing Requirements	63
5.8.1 Responsibilities of the Distributor and Users	63
5.8.2 Preparation of Connection Point Drawings	63
5.8.3 Changes to Connection Point Drawings	64
5.8.4 Validity of the Connection Point Drawings.....	64
5.9 Distribution Data Registration	64
5.9.1 Data to be Registered	64

5.9.2 Stages of Data Registration.....	65
5.9.3 Data Forms.....	65
6 Distribution Planning	67
6.1 Purpose and Scope	67
6.1.1 Purpose.....	67
6.1.2 Scope of Application.....	67
6.2 Distribution Planning Responsibilities and Procedures.....	67
6.2.1 Distribution Planning Responsibilities	67
6.2.2 Submission of Planning Data.....	68
6.2.3 Consolidation and Maintenance of Planning Data.....	69
6.2.4 Evaluation of Proposed Development	69
6.2.5 Preparation of Distribution Development Plan.....	69
6.3 Distribution Planning Studies	70
6.3.1 Distribution Planning Studies to be Conducted.....	70
6.3.2 Voltage Drop Studies.....	70
6.3.3 Short Circuit Studies.....	71
6.3.4 System Loss Studies	71
6.3.5 Distribution Reliability Studies.....	71
6.4 Standard Planning Data.....	72
6.4.1 Energy and Demand Forecast	72
6.4.2 Embedded Generating Unit Data.....	72
6.4.3 User System Data.....	73
6.5 Detailed Planning Data	74
6.5.1 Embedded Generating Unit and Embedded Generating Plant Data	74
6.5.2 User System Data.....	77
7 Distribution Operations.....	79
7.1 Purpose and Scope	79
7.1.1 Purpose.....	79
7.1.2 Scope of Application.....	79
7.2 Operational Responsibilities	80
7.2.1 Operational Responsibilities of the Distributor	80
7.2.2 Operational Responsibilities of Embedded Generators	80
7.2.3 Operational Responsibilities of Other Distribution Users	80
7.3 Operational Arrangements.....	81
7.3.1 Mutual Assistance.....	81
7.3.2 Equipment and Inventory Sharing	81
7.3.3 Joint Purchases.....	81
7.4 Distribution Operations Communications, Notices, and Reports.....	81
7.4.1 Distribution Operations Communications	81
7.4.2 Distribution Operations Notices	82
7.4.3 Distribution Operations Reports	82
7.5 Distribution Maintenance Program.....	82
7.5.1 Preparation of Maintenance Program	82
7.5.2 Submission and Approval of Maintenance Program	83

7.6 Demand and Voltage Control	83
7.6.1 Demand Control Coordination.....	83
7.6.2 Automatic Load Dropping	84
7.6.3 Manual Load Dropping.....	85
7.6.4 Demand Control Initiated by a User	85
7.6.5 Voltage Control.....	85
7.7 Emergency Procedures.....	86
7.7.1 Preparation for Distribution Emergencies	86
7.7.2 Significant Incident Procedures	86
7.7.3 Operation of Embedded Generating Unit in Island Grid	87
7.7.4 Black Start and Resynchronization Procedures	87
7.8 Safety Coordination	87
7.8.1 Safety Coordination Procedures	87
7.8.2 Safety Coordinator	88
7.8.3 Safety Logs and Record of Inter-System Safety Precautions	88
7.8.4 Location of Safety Precautions	89
7.8.5 Implementation of Safety Precautions	89
7.8.6 Authorization of Testing.....	90
7.8.7 Cancellation of Safety Precautions	90
7.9 Distribution Testing and Monitoring	91
7.9.1 Testing Requirements	91
7.9.2 Monitoring of User Effect on the Distribution System.....	91
7.10 System Test.....	92
7.10.1 System Test Requirements.....	92
7.10.2 System Test Request.....	92
7.10.3 System Test Group.....	92
7.10.4 System Test Program	94
7.10.5 System Test Report.....	94
7.11 Embedded Generating Unit Capability Tests	95
7.11.1 Test Requirements	95
7.11.2 Tests to be Performed	95
7.12 Site and Equipment Identification	96
7.12.1 Site and Equipment Identification Requirements	96
7.12.2 Site and Equipment Identification Label	97
8 Distribution Revenue Metering Requirements	99
8.1 Purpose and Scope	99
8.1.1 Purpose.....	99
8.1.2 Scope of Application.....	99
8.1.3 Exemptions	99
8.2 Unbundled Service Provisions.....	99
8.2.1 Electricity Service From Supplier.....	99
8.2.2 Procedure for Collection of Metering Data, Billing, and Settlement	99
8.3 Metering Requirements.....	100
8.3.1 Metering Equipment	100
8.3.2 Metering Responsibility.....	100

8.3.3 Active Energy and Demand Metering	100
8.3.4 Reactive Energy and Demand Metering	100
8.3.5 Integrating Pulse Meters	101
8.4 Metering Equipment Standards	101
8.4.1 Voltage Transformers	101
8.4.2 Current Transformers	101
8.4.3 Meters	101
8.4.4 Integrating Pulse Recorders Required for Unbundled Service	102
8.4.5 Other Accessories	102
8.5 Metering Equipment Testing and Maintenance	103
8.5.1 Instrument Transformer Testing	103
8.5.2 Meter Testing and Calibration	103
8.5.3 Maintenance of Metering Equipment	103
8.5.4 Traceability of Metering Standard	103
8.6 Meter Reading and Metering Data	103
8.6.1 Meter Reading and Recording Responsibility	103
8.6.2 Running Totals of Metered Energy	103
8.6.3 Collection, Processing, and Access to Metering Data	104
8.6.4 Metering Data for Billing and Settlement of Unbundled Services	104
8.6.5 Validation and Substitution of Metering Data	105
8.6.6 Storage and Availability of Metering Data	105
8.7 Settlement Audit Procedures	105
8.7.1 Right to Request Settlement Audit	105
8.7.2 Allocation of Audit Cost	105
8.7.3 Audit Result	105
8.7.4 Audit Appeal	105
8.8 Settlement Dispute Resolution	106
8.8.1 Settlement Dispute Resolution Process—First Stage	106
8.8.2 Settlement Dispute Resolution Process—Second Stage	106
8.8.3 Settlement Dispute Appeal Process	106
9 Distribution Code Transitory Provisions	107
9.1 Purpose and Scope	107
9.1.1 Purpose	107
9.1.2 Scope of Application	107
9.2 Mandates of the Act	107
9.2.1 Objectives of the Electric Power Industry Reform	107
9.2.2 Structure of the Electric Power Industry	108
9.2.3 Generation Sector	108
9.2.4 Transmission Sector	108
9.2.5 Distribution Sector	110
9.2.6 Supply Sector	110
9.2.7 Retail Competition and Open Access	110
9.3 Distribution Asset Boundaries	111
9.3.1 Distributors' Assets	111
9.3.2 Disposal of Sub-transmission Functions, Assets, and Liabilities	111

9.4 Distribution Reliability	112
9.4.1 Submission of Normalized Reliability Data	112
9.4.2 Initial Reliability Targets	112
9.5 Market Transition.....	112
9.5.1 Establishment of the Wholesale Electricity Spot Market	112
9.5.2 Membership to the WESM	112
9.5.3 Market Rules.....	112
9.5.4 The Market Operator.....	113
9.5.5 Guarantee for the Electricity Purchased by Small Utilities	113
9.6 Existing Contracts	113
9.6.1 Effectivity of Existing Contracts	113
9.6.2 New or Amended Contracts.....	113
9.7 Transitional Compliance Plans	114
9.7.1 Statement of Compliance.....	114
9.7.2 Submission of Compliance Plans.....	114
9.7.3 Failure to Submit Plan	114
9.7.4 Evaluation and Approval of Plans	114
9.8 Connection Requirements for New and Renewable Energy Sources	114
9.9 Exemptions For Specific Existing Equipment.....	114
9.9.1 Requests for Permanent Exemption.....	114
9.9.2 Approval of Exemption.....	114

CHAPTER 1

DISTRIBUTION CODE GENERAL CONDITIONS

1.1 PURPOSE AND SCOPE

1.1.1 Purpose

- (a) To cite the legal and 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 Distribution Code;
- (c) To specify the rules for interpreting the provisions of the Distribution Code; and
- (d) To define the common and significant terms and abbreviations used in the Distribution Code.

1.1.2 Scope of Application

This Chapter applies to all Distribution System Users including:

- (a) Distributors;
- (b) Other Distributors connected to Distribution Systems;
- (c) System Operator;
- (d) Embedded Generators;
- (e) Suppliers; and
- (f) End-Users.

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 Distribution Utilities, which include Electric Cooperatives, private Distributors, government-owned utilities, and existing local government units that are franchised to operate Distribution Systems.

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 Distribution Code.

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

1.3.1.3 The DMC shall also initiate an enforcement process for any perceived violations of 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 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 Distributor, or pursuant to any directive given by the ERC or the appropriate government agency.

1.4 DATA, NOTICES, AND CONFIDENTIALITY

1.4.1 Data and Notices

1.4.1.1 The submission of any data under the Distribution Code shall be done through electronic format or any suitable format agreed upon by the concerned parties.

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

1.4.2 Confidentiality

1.4.2.1 All data submitted by any Distribution System User to the Distributor in compliance with the data requirements of the Distribution Code shall be treated by the Distributor 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.

1.4.2.2 Aggregate data shall be made available by the Distributor 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.

1.5 CONSTRUCTION OF REFERENCES

1.5.1 References

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

1.5.2 Cross-References

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.

1.5.3 Definitions

When a word or phrase that is defined in the Definitions Article is more particularly defined in another Article, Section, or Subsection of the Distribution Code, the particular definition in that Article, Section, or Subsection shall prevail if there is any inconsistency.

1.5.4 Foreword, Table of Contents, and Titles

The Table of Contents was added for the convenience of the users of the Distribution Code. The Table of Contents, the Foreword, and the titles of the Chapters, Articles, and Sections shall be ignored in interpreting the Distribution Code provisions.

1.5.5 Mandatory Provisions

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

1.5.6 Singularity and Plurality

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

1.5.7 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.

1.5.8 “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.

1.5.9 “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.

1.5.10 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 are hereby repealed or modified accordingly.

1.6 DEFINITIONS

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

Accountable Manager. A person who has been duly authorized by the Distributor (or User) to sign the Fixed Asset Boundary Documents on behalf of the Distributor (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 System, it is the sum of the Active Power of the individual phases.

Administrative Loss. The component of System Loss that refers to the Energy used in the proper operation of the Distribution System (*e.g.* substation service) and any unbilled Energy that is used for community-related activities.

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 Grid Users that an alert state exists.

Amended Connection Agreement. An agreement between a User and the Distributor (or the Grid Owner), 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 (or the Grid).

Ancillary Service. Support service such as Frequency Regulating and Contingency Reserves, 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 and Security of the Grid and/or the Distribution System.

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 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.

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.

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.

Backup Reserve. Refers to a Generating Unit that has Fast Start capability and can Synchronize with the Grid to provide its declared capacity for a minimum period of eight (8) hours. Also called Cold Standby Reserve.

Balanced Three-Phase Voltages. Three sinusoidal voltages with equal frequency and magnitude and displaced from each other in phase by an angle of 120 degrees.

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.

Blue Alert. A notice issued by the System Operator when a tropical disturbance is expected to make a landfall within 24 hours.

Book Value Per Share. The ratio of book equity to the number of shares outstanding.

Business Day. Any day on which banks are open for business.

Cash Ratio. The ratio of cash plus short-term securities to current liabilities.

Central Dispatch. The process of issuing direct instructions to the Electric Power Industry Participants by the System Operator 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.

Coincident Demand. The Demand that occurs simultaneously with any other Demand.

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 Distributor (or the Grid Owner), 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 (or the Grid).

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.

Contingency Reserve. Generating capacity that is intended to take care of the loss of the largest Synchronized Generating Unit or the power import from a single Grid interconnection, whichever is higher. Contingency Reserve includes Spinning Reserve and Backup Reserve.

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

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

Customer Demand Management. The reduction in the supply of electricity to a Customer or the disconnection of a Customer in a manner agreed upon for commercial purposes, between a Customer and its Generator, Distributor, or Supplier.

Customer Rating Approach. The process of evaluating a Distributor'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 Distributor (or Supplier) and its Customers including payment of bills, application for connection, and customer complaints. It also includes any activity that the Distributor (or Supplier) does to add value or efficiency to these transactions.

Customer Service Program. The totality of the Customer Services offered by a Distributor (or Supplier).

Customer Service Standards. A listing of Customer Services that measure how effectively a Distributor (or Supplier) conducts its day-to-day transactions with its Customers. Customer Service Standards are intended to ensure Customer satisfaction.

Daily Sales. Total annual sales divided by 365 days.

Debt Ratio. The ratio of total liabilities to total assets.

Declared Data. The data provided by the Generator in accordance with the latest/current Generating Unit Parameters.

Declared Net Capability. The Capability of a Generating Unit as declared by the Generator, net of station service.

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 Active Power and/or Reactive Power at a given instant or averaged over a specified interval of time, that is actually delivered or is expected to be delivered by an electrical Equipment or supply System. It is expressed in Watts (W) and/or VARs and multiples thereof.

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

Demand Forecast. The projected Demand and Active Energy related to each 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 Distributor 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 of 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 Generators with Scheduled Generating Units and the Generators whose Generating Units will provide Ancillary Services to implement the final Generation Schedule in real time.

Dispute Resolution Panel. A panel appointed by the DMC (or GMC) to deal with specific disputes related to the provisions of the Distribution Code (or Grid Code).

Distribution Code. 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.

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 Distributor through its Distribution System.

Distribution System. The system of wires and associated facilities belonging to a franchised Distributor, 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. An Electric Cooperative, private corporation, government-owned utility, or existing local government unit, that has an exclusive franchise to operate a Distribution System.

Distributor. Has the same meaning as Distribution Utility.

Earnings per Share. Earnings available for common stockholders divided by the number of shares common stock outstanding.

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.

Electric Power Industry Participant. Refers to any person or entity engaged in the Generation, Transmission, Distribution, or Supply of Electricity.

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. A Generating Plant that is connected to a Distribution System or the System of any User and has no direct connection to the Grid.

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

Embedded Generator. A person or entity that generates electricity using an Embedded Generating Plant.

Emergency State. The Grid operating condition when a Multiple Outage Contingency has occurred without resulting in Total System Blackout and any of the following conditions is present: (a) generation deficiency exists; (b) Grid transmission voltages are outside the limits of 0.90 and 1.10; or (c) the loading level of any transmission line or substation Equipment is above 110 percent of its continuous rating.

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

Energy. Unless otherwise qualified, refers to the Active Energy.

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.

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

Event. An unscheduled or unplanned occurrence of an abrupt change or disturbance in a power System due to fault, Equipment Outage, or Adverse Weather Condition.

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 kA or in MVA, that will flow into a short circuit at a specified point on the Grid, Distribution System, or any User System.

Financial Efficiency Ratio. A financial indicator that measures the productivity in the entity's use of its assets.

Fixed Asset Boundary Document. A document containing information and which defines the 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 Distributor for the Distribution of Electricity.

Frequency. The number of complete cycles of alternating current or voltage per unit time, usually measured in cycle per second or Hertz.

Frequency Control. A strategy used by the System Operator to maintain the Frequency of the Grid within the limits prescribed by the Grid Code by the timely use of Frequency Regulating Reserve, Contingency Reserve, and Demand Control.

Frequency Regulating Reserve. Refers to a Generating Unit that assists in Frequency Control by providing automatic Primary and/or Secondary Frequency response.

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.

Generation Schedule. Refers to the schedule that indicates the hourly output of the Scheduled Generating Units and the list of Generating Units that will provide Ancillary Services for the next Schedule Day.

Generation 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 Generation Schedule.

Generator. Has the same meaning as Generation Company.

Good Industry Practice. The practices and methods not specified in specific standards but are generally accepted by the power industry to be sound and which ensure the safe and reliable planning, operation, and maintenance of a power System.

Grid. The high voltage backbone System of interconnected transmission lines, substations, and related facilities for the conveyance of bulk power. Also known as the Transmission System.

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

Grid Owner. The party who owns the Grid and is responsible for maintaining adequate Grid capacity in accordance with the provisions of the Grid Code.

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 Distributor (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.

Implementing Safety Coordinator. The Safety Coordinator assigned by the Distributor (or the User) to establish the requested Safety Precautions in the User System (or the Distribution System).

Interest Cover. The ratio of earnings before interest and taxes plus depreciation to interest.

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.

Interruption Duration. The period from the initiation of an Interruption up to the time when electric service is restored.

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 one (1) MW or the threshold value specified by the ERC.

Large Generator. A Generation Company whose generating facility at the Connection Point has an aggregate capacity in excess of 20 MW.

Leverage Ratio. A financial indicator that measures how an entity is heavily in debt.

Liquidity Ratio. A financial indicator that measures the ability of an entity to satisfy its short-term obligations as they become due.

Load. An entity or an electrical Equipment that consumes 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 one (1) minute.

Long Term Flicker Severity. A value derived from twelve (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 twelve (12) individual measurements.

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

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

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. An independent group, with equitable representation from Electric Power Industry Participants, whose task includes the operation and administration of the Wholesale Electricity Spot Market in accordance with the Market Rules.

Market Rules. The rules that establish the operation of the Wholesale Electricity Spot Market and the responsibilities of the Market Operator and Market Participants to ensure an efficient, competitive, transparent, and reliable Spot Market.

Market-to-Book Ratio. The ratio of stock price to book value per share.

Market-Value Ratio. A financial indicator that measures how an entity is valued by investors.

Material Effect. A condition that has resulted or expected to result in problems involving 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 one (1) kV up to 34.5 kV.

Minimum Stable Loading. The minimum Demand that a Generating Unit can safely maintain for an indefinite period.

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). The total number of momentary customer power Interruptions within a given period divided by the total number of customers served within the same period.

Momentary Interruption. An Interruption whose duration is limited to the period required to restore service by automatic or supervisory controlled switching operations or by manual switching at a location where an operator is immediately available.

Multiple Outage Contingency. An Event caused by the failure of two or more Components of the Grid including Generating Units, transmission lines, and transformers.

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).

National Transmission Corporation (TRANSCO). The corporation that assumed the authority and the responsibility of planning, maintaining, constructing, and centrally operating the high-voltage transmission system, including the construction of Grid interconnections and the provision of Ancillary Services.

Negative Sequence. One of the three (3) sequence components that represent an unbalanced set of voltages or currents.

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 Generator.

Net Profit Margin. The ratio of net profits after taxes to sales.

Non-Coincident Demand. Individual maximum Demand regardless of time of occurrence.

Non-Scheduled Generating Plant. A Generating Plant whose Generating Units are not subject to Central Dispatch.

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

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 error, 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 margin of generation over the total Demand plus losses that is necessary for ensuring Power Quality and the Security of the Grid. Operating Margin is the sum of the Frequency Regulating Reserve and the Contingency Reserve.

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.

Outage Duration. The period from the initiation of the Outage until the affected Component or its replacement becomes available to perform its intended function.

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

Planned Activity Notice. A notice issued by a User to the Distributor for any planned activity, such as a planned Shutdown or Scheduled Maintenance of its Equipment, at least three (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 Generators, the Grid Owner and 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 are measured in the Grid, Distribution System, or any User System.

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 Distributor's (or Supplier's) Customer Service Program by comparing its actual performance with the targets approved by the ERC.

Price-Earnings Ratio (P/E). The ratio of stock price to earnings per share.

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.

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 a three-phase system, 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.

Registered Data. Data submitted by a User to the Distributor Grid (or Owner) at the time of connection of the User System to the Distribution System (or Grid).

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 Distributor (or the User) when it requests that Safety Precautions be established in the User System (or the Distribution System).

Return on Assets (ROA). The ratio of net profits after taxes to average total assets.

Return on Investment (ROI). The most common name given by analysts to return on assets.

Safety Coordinator. A person designated/authorized by the Distributor (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.

Schedule Day. The period from 0000H to 2400H in a day.

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 Distributor or User, as the case may be.

Scheduling. The process of matching the offers to supply Energy and provide Ancillary Services with the bids to buy Energy and the operational support required by the Grid, to prepare the Generation Schedule, which takes into account the operational constraints in the Grid.

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. In the Grid Code, it is an Event on the Grid, Distribution System, or the System of any User that has a serious or widespread effect on the Grid, the Distribution System, and/or the User System. In the Distribution Code, it is 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 Distributor or any User if a Significant Incident has transpired on the Distribution System or the System of the User, as the case may be.

Single Outage Contingency. An Event caused by the failure of one Component of the Grid including a Generating Unit, transmission line, or a transformer.

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.

Spinning Reserve. The component of Contingency Reserve, which is Synchronized to the Grid and ready to take on Load. Also called Hot Standby Reserve.

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 Distributor 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. Refers to 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 Generator or a Distributor in the franchise area of a Distribution Utility using the wires of the Distribution Utility concerned.

Sustained Interruption. Any Interruption that is not classified as a Momentary Interruption.

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). The total duration of sustained customer power Interruption within a given period divided by the total number of customers served within the same period.

System Average Interruption Frequency Index (SAIFI). The total number of sustained customer power Interruptions within a given period divided by the total number of customers served within the same period.

System Loss. In a Distribution System, it is the difference between the electric Energy purchased and/or generated and the electric Energy sold by the Distributor.

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 Distributor or the User who plans to undertake a System Test and who submits a System Test Request to the Distributor (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 Distributor, affected Users, and the members of the System Test Group.

System Test Request. A notice submitted by the System Test Proponent to the Distributor 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.

Top-up. The Supply of Electricity by the Distributors to the Customer on a continuing or regular basis to compensate for any shortfall between the Customer's total supply requirements and those met from other sources.

Total Demand Distortion (TDD). The ratio of the root-mean-square value of the harmonic content to the root-mean-square value of the rated or maximum fundamental quantity, expressed in percent.

Total Harmonic Distortion (THD). The ratio of the root-mean-square value of the harmonic content to the root-mean-square value of the fundamental quantity, expressed in percent.

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 Distributor (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 of Electricity. Refers to the conveyance of electricity through the Grid.

Transmission System. Has the same meaning as Grid.

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 percent of the nominal voltage.

User. In the Grid Code, it is a person or entity that uses the Grid and related Grid facilities. In the Distribution Code, it is a person or entity that uses the Distribution System and related Distribution facilities. User also refers to a person or entity to which the Grid Code or 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 Grid or Distribution System.

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 System Operator, Distributor, or User to maintain the voltage of the Grid, Distribution System, or the User System within the limits prescribed by the Grid Code or the Distribution Code.

Voltage Dip. Has the same meaning as Voltage Sag.

Voltage Reduction. The method used to temporarily decrease Demand by a reduction of the System voltage.

Voltage Sag. A Short Duration Voltage Variation where the RMS value of the voltage decreases to between 10 percent and 90 percent of the nominal value.

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

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 Load Curtailment (VLC). The agreed self-reduction of Demand by identified industrial End-Users to assist in Frequency Control when generation deficiency exists.

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. The electricity market established by the DOE pursuant to Section 30 of the Act.

Yellow Alert. A notice issued by the System Operator when the Contingency Reserve is less than the capacity of the largest Synchronized Generating Unit or power import from a single interconnection, whichever is higher.

1.7 ABBREVIATIONS

AC	Alternating Current
ALD	Automatic Load Dropping
DMC	Distribution Management Committee
DOE	Department of Energy
EBIT	Earnings Before Interest and Taxes
ERC	Energy Regulatory Commission
GW	Gigawatt
GWh	Gigawatt-hour
HV	High Voltage
IEC	International Electrotechnical Commission
IRR	Implementing Rules and Regulations
KA	Kiloampere
KVARh	Kilovar-hour

kW	Kilowatt
kWh	Kilowatt-hour
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MLD	Manual Load Dropping
MV	Medium Voltage
MVA	Megavolt-ampere
MVAR	Megavar
MVARh	Megavar-hour
MW	Megawatt
MWh	Megawatt-hour
NEA	National Electrification Administration
PDP	Power Development Program
P/E	Price-Earnings Ratio
ROA	Return on Assets
ROI	Return on Investment
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SPUG	Small Power Utility Group
TDD	Total Demand Distortion
THD	Total Harmonic Distortion
TRANSCO	National Transmission Corporation
UFR	Underfrequency Relay
V	Volts
VA	Volt Ampere
VAR	Volt Ampere Reactive
W	Watt
WESM	Wholesale Electricity Spot Market
Wh	Watt-hour
X/R	Reactance/Resistance

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CHAPTER 2

DISTRIBUTION MANAGEMENT

2.1 PURPOSE AND SCOPE

2.1.1 Purpose

- (a) To facilitate the monitoring of compliance with the Distribution Code at the operations level;
- (b) 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
- (c) To specify the processes for the settlement of disputes, enforcement, and revision of the Distribution Code.

2.1.2 Scope of Application

This Chapter applies to all Distribution System Users including:

- (a) Distributors;
- (b) Other Distributors connected to the Distribution System;
- (c) System Operator
- (d) Embedded Generators;
- (e) Suppliers; and
- (f) End-Users.

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 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) Coordinate Distribution Code dispute resolution and make appropriate recommendations to the ERC;
- (e) Initiate the Distribution Code enforcement process and make recommendations to the ERC;
- (f) Initiate and coordinate revisions of the 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 Distribution System User.

2.2.2 Membership of the DMC

- 2.2.2.1 The DMC shall be composed of the following members who shall be appointed by the ERC:
 - (a) Three (3) members nominated by private and local government Distributors;
 - (b) Three (3) members nominated by the Electric Cooperatives, one (1) each from Luzon, Visayas, and Mindanao;
 - (c) One (1) member nominated by Embedded Generators;
 - (d) One (1) member nominated by industrial Customers;
 - (e) One (1) member nominated by commercial Customers;
 - (f) One (1) member nominated by residential consumer groups;
 - (g) One (1) member nominated by the Grid Owner;
 - (h) One (1) member nominated by the System Operator; and
 - (i) One (1) 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 (3) members nominated by the DMC.
- 2.2.2.5 The members of the DMC shall have sufficient technical background and experience 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 All members of the DMC shall have a term of three (3) years, and shall be allowed only one re-appointment.
- 2.2.3.2 For the first appointees to the DMC, the Chairman shall hold office for three (3) years, seven (7) members shall hold office for two (2) years, and the remaining members shall hold office for one (1) year. The ERC shall determine the terms of office of the initial DMC members.
- 2.2.3.3 Appointment to any future vacancy shall be only for the remaining term of the predecessor.

2.2.4 DMC Support Staff and Operating Cost

2.2.4.1 The DMC operating costs, including the maintenance of a permanent support staff, shall be shared among all Distributors as a direct proportion of their annual peak Demand or annual Energy sales. The ERC shall issue the guidelines pertaining to the budget of the DMC.

2.2.4.2 The DMC shall prepare and submit the budget requirements for the following year by September of the current year. Honoraria of DMC members and subcommittee members, if any, shall be included in the operating cost of the DMC.

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 business. These include:

- (a) Administration and operation of the Committee;
- (b) Establishment and operation of DMC subcommittees;
- (c) Evaluation of Distribution System operations reports;
- (d) Coordination of dispute resolution process;
- (e) Monitoring of Distribution Code enforcement;
- (f) Revision of 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 issues based on consensus rather than by simple majority voting.

2.3 DISTRIBUTION MANAGEMENT SUBCOMMITTEES

2.3.1 Distribution Technical Standards Subcommittee

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

- (a) Developing and coordinating technical standards including:
 - (1) Distribution planning standards;
 - (2) Distribution Equipment standards;
 - (3) Distribution standard operating procedures;
 - (4) Distribution performance standards; and
 - (5) Distribution financial capability standards;
- (b) Developing and recommending procedures for:
 - (1) Joint purchases of common Equipment;

- (2) Sharing of parts inventories;
- (3) Mutual assistance; and
- (4) Emergency response;

(c) Reporting on Distribution Operations.

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

2.3.1.3 The members of the Distribution Technical Standards Subcommittee shall have sufficient technical background and experience in the development and implementation of technical standards.

2.3.2 Distribution Reliability and Protection Subcommittee

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

- (a) Coordinating and recommending standards for distribution protection;
- (b) Reviewing and recommending reliability performance standards; and
- (c) Managing reliability data.

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

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

2.3.3 Distribution Tariff Framework Subcommittee

2.3.3.1 The DMC shall establish a permanent Distribution Tariff Framework Subcommittee. The subcommittee shall be responsible for developing and recommending to ERC a common framework for establishing tariffs for wheeling and Ancillary Services at the distribution level and in proposing revisions to the framework.

2.3.3.2 The chairman and members of the Distribution Tariff Framework Subcommittee shall be appointed by the DMC.

2.3.3.3 The members of the Distribution Tariff Framework Subcommittee shall have sufficient technical background and experience in Distribution tariff design.

2.3.4 Distribution Metering and Settlements Subcommittee

2.3.4.1 The DMC shall establish a permanent Distribution Metering and Settlements Subcommittee with the following functions:

- (a) Reviewing and recommending metering standards;
- (b) Reviewing and recommending settlement procedures; and
- (c) Acting as the dispute resolution panel for metering settlement disputes.

2.3.4.2 The chairman and members of the Distribution Metering and Settlements Subcommittee shall be appointed by the DMC.

2.3.4.3 The members of the Distribution Metering and Settlements Subcommittee shall have sufficient technical background and experience in metering and settlement of billing disputes.

2.3.5 Other Distribution Subcommittees

The DMC may establish other ad hoc subcommittees as necessary.

2.4 DISTRIBUTION CODE DISPUTE RESOLUTION

2.4.1 Distribution Code Disputes

Disputes will arise from time to time regarding how the Distribution Code is being administered and interpreted. The Distribution Code dispute resolution process outlined in this Article applies to the Distributor and all Users of the Distribution System with respect to the provisions of the Distribution Code. It does not apply to disputes involving billing and settlement, which are handled according to the settlement procedure in the Distribution Revenue Metering Requirements Chapter.

2.4.2 Distribution Code Dispute Resolution Process

The Distribution Code dispute resolution process shall include the following steps:

- (a) When a dispute arises between parties which is not resolved informally, one of the parties shall, if he/she wishes, register the dispute in writing to the DMC and the other party or parties;
- (b) The parties shall meet to discuss and attempt to resolve the dispute within a period to be prescribed by the DMC. If resolved, the resolution shall be documented and a written record provided to all parties and to the DMC;
- (c) If the dispute is not resolved, a committee of representatives from both parties shall be formed by the DMC to discuss and attempt to resolve the dispute within a period to be prescribed by the DMC. If resolved, the resolution shall be documented and a written record provided to all parties and the DMC; and
- (d) If the dispute is not resolved at stage (c), the committee of representatives shall refer the dispute to the DMC for appropriate action. The DMC shall either create an independent Distribution Code Dispute Resolution Panel or refer the matter directly to the ERC for resolution.

2.4.3 Distribution Code Dispute Resolution Panel

2.4.3.1 The Distribution Code Dispute Resolution Panel shall consist of three (3) or five (5) persons. The panel shall include members who have the technical background to understand the technical merits and implications of the disputing parties' arguments.

2.4.3.2 The panel shall hold meetings, within a period to be prescribed by the DMC, to hear the contending parties and to receive documents supporting

their positions. The proceedings and recommendations of the Panel shall be documented and provided to both parties and the DMC.

- 2.4.3.3 The DMC shall submit a report regarding the dispute, including any recommendations, to the ERC who shall render the final ruling on the matter.

2.4.4 Cost of Dispute Resolution

The cost of the Dispute Resolution Process shall be shared in one of the following ways:

- (a) If the dispute is resolved, part of the resolution shall include an allocation of the cost of the process; and
- (b) If the dispute is not resolved (*e.g.*, the dispute is dropped or becomes a legal action), the parties shall share equally the cost of the dispute resolution process.

2.5 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 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 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 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 Distribution Code.

2.5.3 Unforeseen Circumstances

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

2.5.4 Distribution Code Revision Process

- 2.5.4.1 Any party who has a proposal to revise any provision of the Distribution Code shall submit the proposed revision, including the supporting arguments and data, to the DMC or to the appropriate DMC subcommittee who shall evaluate the proposal.
- 2.5.4.2 If the DMC or the appropriate DMC subcommittee agrees with the proposed revision, it shall make the appropriate recommendations to the ERC.
- 2.5.4.3 If the DMC or the appropriate DMC subcommittee disagrees with the proposed revision, it shall submit a report, including the justifications why it disagrees with the proposed revision, to the ERC.
- 2.5.4.4 The ERC shall render the final decision on any matter pertaining to Distribution Code 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 (4) 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 Within one (1) week following a Significant Incident in the Distribution System or the User System, the Distributor 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.

- 2.6.2.2 Within one (1) month following the receipt of the Distributor'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 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 AND SCOPE

3.1.1 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.

3.1.2 Scope of Application

This Chapter applies to all Distribution System Users including:

- (a) Distributors;
- (b) Suppliers;
- (c) Embedded Generators; and
- (d) End-Users.

3.2 POWER QUALITY STANDARDS FOR DISTRIBUTORS

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 Distributor 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 root-mean-square (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 one minute. A Short Duration Voltage Variation is a Voltage Swell if the RMS value of the voltage increases to between 110 percent and 180 percent 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 percent and 90 percent 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 one minute. A Long Duration Voltage Variation is an Undervoltage if the RMS value of the voltage is less than or equal to 90 percent 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 percent of the nominal value.
- 3.2.3.4 The Distributor 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 Distributor to comply with a more stringent Voltage Variation limits, which shall be determined from technical and economic studies.
- 3.2.3.5 The Distributor 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 harmonic content to the RMS value of the fundamental quantity, expressed in percent.

3.2.4.3 The Total Demand Distortion (TDD) shall be defined as the ratio of the RMS value of the harmonic content to the RMS value of the rated or maximum fundamental quantity, expressed in percent.

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

3.2.4.5 At any User System, the TDD of the current shall not exceed five percent (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 percent 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 DISTRIBUTORS

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 Distributors 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); and
- (c) Momentary Average Interruption Frequency Index (MAIFI).

3.3.2.2 The System Average Interruption Frequency Index shall be defined as the total number of sustained Customer power Interruptions within a given period divided by the total number of Customers served within the same period.

3.3.2.3 The System Average Interruption Duration Index shall be defined as the total duration of sustained Customer power Interruptions within a given period divided by the total number of Customers served within the same period.

3.3.2.4 The Momentary Average Interruption Frequency Index shall be defined as the total number of momentary Customer power Interruptions within a given period divided by the total number of Customers served within the same period.

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 three (3) days prior to the loss of power;
- (d) Outages that are initiated by the System Operator/Market Operator during the occurrence of Significant Incidents or the failure of their facilities;

- (e) 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 Distributor; and
- (f) Outages due to other 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 Distributor shall submit every three (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 DISTRIBUTORS

3.4.1 System Loss Classifications

- 3.4.1.1 System Loss shall be classified into three categories: Technical Loss, Non-Technical Loss, and Administrative 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, and meter tampering.
- 3.4.1.4 The Administrative Loss shall include the Energy that is required for the proper operation of the Distribution System and any unbilled Energy for community-related activities.

3.4.2 System Loss Cap

- 3.4.2.1 The Distributor 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 Distributor can pass on to its End-Users. Separate caps shall be set for the Technical and Non-Technical Losses.
- 3.4.2.3 The Distributor shall submit to ERC an application for the approval of its Administrative Loss. The allowance for Administrative Loss shall be approved by the ERC, after due notice and hearing, based on connected essential load.

3.4.3 Power Factor at the Connection Point

- 3.4.3.1 All Users of the Distribution System shall maintain a Power Factor of not less than 85 percent lagging at the Connection Point.
- 3.4.3.2 The Distributor 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.

- 3.4.3.3 The Distributor 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 DISTRIBUTORS AND SUPPLIERS

3.5.1 Customer Service Standards

- 3.5.1.1 The Customer Service Standards for Distributors 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 Distributor (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 Distributor (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 Distributor (or Supplier) shall include:
- (a) Prescriptive Approach; and
 - (b) Customer Rating Approach.
- 3.5.2.2 In the Prescriptive Approach, the Distributor (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 Distributor (or Supplier) shall commission an independent entity, accredited by the ERC, to conduct a Transactions Survey.

3.5.3 Customer Service Standards for Distributors

- 3.5.3.1 The Distributor shall submit to ERC for approval the target levels for the Customer Services listed in Table 3-1. The Distributor shall justify the basis for the target levels of performance.
- 3.5.3.2 The Distributor 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 Distributor 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 Philippine Electrical Code (PEC) Parts 1 and 2 shall govern the safety requirements for electrical installation, operation, and maintenance. Part 1 of PEC pertains to the wiring System in premises of End-Users. Part 2 covers electrical Equipment and associated work practices employed by the Electric Utility. Compliance with these Codes is mandatory. Hence, the Distributor 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 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 Distributors 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.

3.6.3 Submission of Safety Records and Reports

The Distributor (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 3.6.2.

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CHAPTER 4

FINANCIAL CAPABILITY STANDARDS FOR DISTRIBUTION AND SUPPLY

4.1 PURPOSE AND SCOPE

4.1.1 Purpose

- (a) To specify the financial capability standards for Distributors and Suppliers;
- (b) To safeguard against the risk of financial non-performance;
- (c) To ensure the affordability of electric power supply while maintaining the required quality and reliability; and
- (d) To protect the public interest.

4.1.2 Scope of Application

This Chapter applies to all Distribution System Users including:

- (a) Distributors; and
- (b) Suppliers.

4.2 FINANCIAL STANDARDS FOR DISTRIBUTORS

4.2.1 Financial Ratios

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.

4.2.2 Leverage Ratios

4.2.2.1 The Leverage Ratios for the Distributor shall include the following:

- (a) Debt Ratio;
- (b) Debt-Equity Ratio; and
- (c) Interest Cover.

4.2.2.2 The Debt Ratio shall measure the degree of indebtedness of financial leverage of the Distribution Utility. The Debt Ratio shall be calculated as the ratio of Total Liabilities to Total Assets.

4.2.2.3 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.

- 4.2.2.4 The Debt Ratio can also be calculated as the ratio of Long-Term Debt plus Value of Leases plus Equity. Equity is the sum of Outstanding Capital Stock, Retained Earnings, and Revaluation Increment.
- 4.2.2.5 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.
- 4.2.2.6 The Debt-Equity Ratio shall be used to compare the financial commitments of creditors relative to those of the Distribution Utility.
- 4.2.2.7 The Debt-Equity Ratio shall be used as a measure of the degree of financial leverage of the Distribution Utility.
- 4.2.2.8 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.
- 4.2.2.9 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.

4.2.3 Liquidity Ratios

- 4.2.3.1 Liquidity Ratios shall include the following:
- (a) Financial Current Ratio; and
 - (b) Quick Ratio.
- 4.2.3.2 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.
- 4.2.3.3 The Financial Current Ratio shall be used as a measure of the margin of liquidity of the Distribution Utility.
- 4.2.3.4 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.
- 4.2.3.5 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.

4.2.4 Financial Efficiency Ratios

4.2.4.1 Financial Efficiency Ratios shall include the following:

- (a) Sales-to-Assets Ratio; and
- (b) Average Collection Period.

4.2.4.2 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.

4.2.4.3 The Average Collection Period (ACP) shall measure how quickly other entities 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.

4.2.4.4 The Average Collection Period shall be used to evaluate the credit and collection policies of the Distribution Utility.

4.2.4.5 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.

4.2.5 Profitability Ratios

4.2.5.1 Profitability Ratios shall include the following:

- (a) Net Profit Margin; and
- (b) Return on Assets.

4.2.5.2 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.

4.2.5.3 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.

4.2.5.4 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.

- 4.2.5.5 The Return on Assets shall be used to measure the overall effectiveness of the Distribution Utility in generating profits from their available assets.

4.2.6 Submission and Evaluation

- 4.2.6.1 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.
- 4.2.6.2 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.
- 4.2.6.3 Failure to submit to the ERC the requirements shall serve as grounds for the imposition of appropriate sanctions, fines, penalties, or adverse evaluation.
- 4.2.6.4 All submissions shall be certified under oath by a duly authorized officer.

4.3 FINANCIAL STANDARDS FOR SUPPLIERS

4.3.1 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.

4.3.2 Financial Requirements

- 4.3.2.1 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).
- 4.3.2.2 If the applicant has not been in existence for at least two (2) 12-month periods, it shall provide true copies of audited balance sheet, income statements, and cash flow statements for the life of the business.
- 4.3.2.3 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.

4.3.3 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.

4.3.4 Financial Standards for Customer Protection

- 4.3.4.1 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).
- 4.3.4.2 The amount of the security deposit shall be based upon sales value that the applicant will collect by way of deposits or advance payments.
- 4.3.4.3 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.
- 4.3.4.4 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.
- 4.3.4.5 The applicant shall designate the geographic area (or customer class) it intends to serve.
- 4.3.4.6 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).
- 4.3.4.7 The financial standards for customer protection apply primarily to all the applicants' funds, including deposits or advances, from customers prior to providing services.

4.3.5 Certification Standards

- 4.3.5.1 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.
- 4.3.5.2 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.
- 4.3.5.3 The applicant shall designate the geographic area (or customer class) it intends to serve.
- 4.3.5.4 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).
- 4.3.5.5 Certifications standards apply primarily to applicants who do not plan to collect funds or advanced deposits prior to providing services.

4.3.6 Financial Standards for Billing, Collection, and Profitability

- 4.3.6.1 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.
- 4.3.6.2 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.

- 4.3.6.3 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.
- 4.3.6.4 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.
- 4.3.6.5 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.
- 4.3.6.6 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.
- 4.3.6.7 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.
- 4.3.6.8 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:
- (a) Those with government accounts and accounts under litigation; and
 - (b) Those without government accounts and without accounts under litigation.
- 4.3.6.9 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).
- 4.3.6.10 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.

4.3.7 Organizational and Managerial Resource Requirements

- 4.3.7.1 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.
- 4.3.7.2 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 Grid Owner 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.

4.3.8 Submission and Evaluation

- 4.3.8.1 The Supplier shall submit to the ERC true copies of audited balance sheet, income statements, and cash flow statements for the two most recent twelve (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.
- 4.3.8.2 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.
- 4.3.8.3 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.

- 4.3.8.4 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.
- 4.3.8.5 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.
- 4.3.8.6 The applicant shall inform the ERC of its proposed geographic service area.
- 4.3.8.7 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.
- 4.3.8.8 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.
- 4.3.8.9 Failure to submit the requirements to the ERC, shall serve as grounds for the imposition of appropriate sanctions, fines, penalties, or adverse evaluation.
- 4.3.8.10 All submissions shall be certified under oath by a duly authorized officer.

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CHAPTER 5

DISTRIBUTION CONNECTION REQUIREMENTS

5.1 PURPOSE AND SCOPE

5.1.1 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 Distributor from the User and to list the data to be provided by the Distributor to the User.

5.1.2 Scope of Application

- 5.1.2.1 This Chapter applies to all Distribution System Users including:
 - (a) Distributors;
 - (b) Embedded Generators;
 - (c) Large Customers; and
 - (d) Any other entity with a User System connected to the Distribution System.
- 5.1.2.2 This Chapter does not apply to small retail Customers being provided bundled service by the Distributor. Such Customers shall be governed by the rules and procedures established by the Distributor under its franchise, and in conformity with the applicable rules and regulations issued by the ERC.

5.2 DISTRIBUTION TECHNICAL, DESIGN, AND OPERATIONAL CRITERIA

5.2.1 Power Quality Standards

- 5.2.1.1 The Distributor shall ensure that at any Connection Point in the Distribution System, the Power Quality standards specified in Article 3.2 are complied with.
- 5.2.1.2 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.

5.2.2 Frequency Variations

- 5.2.2.1 The Distributor 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.
- 5.2.2.2 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 five (5) seconds to allow the System Operator to undertake measures to correct the situation.

- 5.2.2.3 The Distributor shall take into account the maximum estimated Frequency Variation during emergency conditions in the specification of Distribution Equipment.

5.2.3 Voltage Variations

- 5.2.3.1 The Long Duration Voltage Variation at any Connection Point during normal conditions shall be within the limits specified in Section 3.2.3.
- 5.2.3.2 The Distributor shall consider the maximum estimated Voltage Swell in the selection of the voltage ratings of Distribution Equipment.
- 5.2.3.3 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.

5.2.4 Power Factor

- 5.2.4.1 The User shall maintain a Power Factor not less than 85 percent lagging at the Connection Point in the Distribution System.
- 5.2.4.2 The Distributor shall correct feeder and substation feeder bus Reactive Power demand to a level that will economically reduce the Technical Loss.
- 5.2.4.3 The Distributor may establish penalties and incentives for User Power Factor at the Connection Point based on the target level.

5.2.5 Harmonics

- 5.2.5.1 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.
- 5.2.5.2 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.

5.2.6 Voltage Unbalance

- 5.2.6.1 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.
- 5.2.6.2 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.

5.2.7 Flicker Severity

- 5.2.7.1 The Flicker Severity at any Connection Point in the Distribution System shall not exceed the limits specified in Section 3.2.6.
- 5.2.7.2 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.

5.2.8 Transient Voltage Variations

5.2.8.1 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.

5.2.8.2 The Distributor and the User shall take into account the effect of electrical transients when specifying the insulation of their electrical Equipment.

5.2.9 Protection Arrangements

5.2.9.1 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.

5.2.9.2 The requirements for the protection system at the Connection Point shall be agreed upon by the Distributor and the User during the application for connection or modification of an existing connection and shall be reviewed from time to time by the Distributor, with the concurrence of the User.

5.2.9.3 The User System shall be designed and operated with protective devices in accordance with the requirements of the Distributor.

5.2.9.4 Unless the Distributor advises otherwise, the User shall not use current-limiting protective devices to limit the fault current infeed to the Distribution System.

5.2.9.5 The Fault Clearance Time shall be within the limits established by the Distributor in accordance with the protection policy adopted for the Distribution System.

5.2.9.6 The Distributor 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.

5.2.9.7 The User shall consider in the design of its protection System the possible disconnection of only one phase or two phases during fault conditions.

5.2.10 Equipment Short Circuit Rating

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

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

5.2.11 Grounding Requirements

5.2.11.1 The Distributor 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.

5.2.11.2 The method of Grounding at the User System shall comply with the Grounding standards and specifications of the Distributor.

- 5.2.11.3 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.

5.2.12 Monitoring and Control Equipment Requirements

- 5.2.12.1 The Distributor and the User shall agree on the mode of monitoring and control.
- 5.2.12.2 The Distributor shall provide, install, and maintain the telemetry outstation and all associated Equipment needed to monitor the User System.
- 5.2.12.3 If the User agrees that the Distributor shall control the switchgear in the User System, the Distributor shall install the necessary control outstation, including the control interface for the switchgear.

5.2.13 Equipment Standards

- 5.2.13.1 All Equipment at the Connection Point shall comply with the requirements of the IEC Standards or their equivalent national standards.
- 5.2.13.2 All Equipment at the Connection Point shall be designed, manufactured, and tested in accordance with the quality assurance requirements of the ISO 9000 series.
- 5.2.13.3 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.

5.2.14 Maintenance Standards

- 5.2.14.1 All Equipment at the Connection Point shall be operated and maintained in accordance with Good Industry Practice and in a manner that shall not pose a threat to the safety of any personnel or cause damage to the Equipment of the Distributor or the User.
- 5.2.14.2 The Distributor 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.
- 5.2.14.3 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 Distributor.

5.3 PROCEDURES FOR DISTRIBUTION CONNECTION OR MODIFICATION

5.3.1 Connection Agreement

- 5.3.1.1 Any User seeking a new connection to the Distribution System shall secure the required Connection Agreement with the Distributor prior to the actual connection to the Distribution System.
- 5.3.1.2 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.

5.3.2 Amended Connection Agreement

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

5.3.2.2 The Amended Connection Agreement shall include provisions for the submission of additional information required by the Distributor and prescribed by the ERC.

5.3.3 Distribution Impact Studies

5.3.3.1 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.

5.3.3.2 The Distributor shall conduct Distribution Impact Studies to evaluate the impact of the proposed connection or modification to an existing connection on the Distribution System. The evaluation shall include the following:

- (a) Impact of short circuit infeed to the Distribution Equipment;
- (b) Coordination of protection System; and
- (c) Impact of User Development on Power Quality.

5.3.3.3 The Distributor 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.

5.3.4 Application for Connection or Modification

5.3.4.1 Any User applying for connection or a modification of an existing connection to the Distribution System shall submit to the Distributor 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 6.4; and
- (c) The Completion Date of the proposed User Development.

5.3.4.2 The User shall submit the planning data in three (3) stages, according to their degree of commitment and validation as described in Section 5.9.2. These include:

- (a) Preliminary Project Planning Data;

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

5.3.5 Processing of Application

- 5.3.5.1 The Distributor shall establish the procedure for the processing of applications for connection or modification of an existing connection to the Distribution System.
- 5.3.5.2 The Distributor shall process the application for connection or modification to an existing connection within 30 days from the submission of the completed application form.
- 5.3.5.3 The Distributor shall evaluate the impact of the proposed User Development on the Distribution System.
- 5.3.5.4 After evaluating the application submitted by the User, the Distributor shall inform the User whether the proposed User Development is acceptable or not.
- 5.3.5.5 If the application of the User is acceptable, the Distributor and the User shall sign a Connection Agreement or an Amended Connection Agreement, as the case may be.
- 5.3.5.6 If the application of the User is not acceptable, the Distributor shall notify the User why its application is not acceptable. The Distributor shall include in its notification a proposal on how the User's application will be acceptable to the Distributor.
- 5.3.5.7 The User shall accept the proposal of the Distributor within 30 days, or a longer period specified in the Distributor's proposal, after which the proposal automatically lapses.
- 5.3.5.8 The acceptance by the User of the Distributor's proposal shall lead to the signing of a Connection Agreement or an Amended Connection Agreement.
- 5.3.5.9 If the Distributor and the User cannot reach agreement on the proposed connection or modification to an existing connection, the Distributor or the User may bring the matter before the ERC for resolution.
- 5.3.5.10 If a Connection Agreement or an Amended Connection Agreement is signed, the User shall submit to the Distributor, within 30 days from signing or a longer period agreed to by the Distributor and the User, the Detailed Planning Data pertaining to the proposed User Development, as specified in Article 6.5.

5.3.6 Submittals Prior to the Commissioning Date

- 5.3.6.1 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 and settings referred to in Section 5.4.9 for Embedded Generating Units and in Section 5.5.2 for other Users;
- (c) Information to enable the Distributor to prepare the Fixed Asset Boundary Document referred to in Article 5.6 including the names of Accountable Managers;
- (d) Electrical Diagrams of the User's Equipment at the Connection Point as described in Article 5.7;
- (e) Information that will enable the Distributor to prepare the Connection Point Drawings, referred to in Article 5.8;
- (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 7.8;
- (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 7.7.2;
- (h) Proposed Maintenance Program; and
- (i) Test and Commissioning procedure for the Connection Point and the User Development.

5.3.7 Commissioning of Equipment and Physical Connection to the Distribution System

- 5.3.7.1 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 5.3.6.
- 5.3.7.2 The User shall then submit to the Distributor a statement of readiness to connect, which shall include the Test and Commissioning report.
- 5.3.7.3 Upon acceptance of the User's statement of readiness to connect, the Distributor shall, within 15 days, issue a certificate of approval to connect.
- 5.3.7.4 The physical connection to the Distribution System shall be made only after the certificate of approval to connect has been issued by the Distributor to the User.

5.4 REQUIREMENTS FOR EMBEDDED GENERATORS

5.4.1 Requirements Relating to the Connection Point

- 5.4.1.1 The Embedded Generator's Equipment shall be connected to the Distribution System at the voltage level agreed to by the Distributor and the Generator based on the Distribution Impact Studies.
- 5.4.1.2 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.

- 5.4.1.3 Disconnect switches shall also be provided and arranged to isolate the Circuit Breaker for maintenance purposes.

5.4.2 Embedded Generating Unit Power Output

- 5.4.2.1 The Embedded Generating Unit shall be capable of continuously supplying its Active Power output, as specified in the Generator'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.
- 5.4.2.2 The Embedded Generating Unit shall be capable of supplying its Active Power and Reactive Power outputs, as specified in the Generator's Declared Data, within the Voltage Variation specified in Section 5.2.3 during normal operating conditions.
- 5.4.2.3 The Embedded Generating Unit shall be capable of supplying its Active Power output, as specified in the Generator's Declared Data, within the limits of 0.85 Power Factor lagging and 0.90 Power Factor leading at the Generating Unit's terminals, in accordance with its Reactive Power Capability Curve.

5.4.3 Frequency Withstand Capability

- 5.4.3.1 If the System frequency momentarily rises to 62.4 Hz or falls to 57.6 Hz, Embedded Generating Units shall remain in synchronism with the Grid for at least five (5) seconds, as specified in Section 5.2.2. The Distributor, in consultation with the System Operator, may waive this requirement, if there are sufficient technical reasons to justify the waiver.
- 5.4.3.2 The Generator 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 Generator shall decide whether or not to disconnect its Embedded Generating Unit from the Distribution System.

5.4.4 Unbalance Loading Withstand Capability

- 5.4.4.1 The Embedded Generating Unit shall meet the requirements for Voltage Unbalance as specified in Section 5.2.6.
- 5.4.4.2 The Embedded Generating Unit shall also be required to withstand without tripping, the unbalance loading during clearance by the Backup Protection of a close-up phase-to-phase fault on the Distribution System.

5.4.5 Speed-Governing System

- 5.4.5.1 During Island Grid operation, an Embedded Generating Unit providing Ancillary Services for Frequency Regulating Reserve shall provide Frequency Control to the Island Grid.
- 5.4.5.2 The Embedded Generating Unit providing Ancillary Services for Frequency Regulating Reserve shall be fitted with a fast-acting speed-governing system. The speed-governing System shall have an overall speed-droop characteristic of five percent (5%) or less. Unless waived by the

Distributor in consultation with the Grid Owner and the System Operator, the speed-governing System shall be capable of accepting raise and lower signals from the Control Center of the System Operator.

5.4.6 Excitation Control System

- 5.4.6.1 The Embedded Generating Unit providing Ancillary Services for Reactive Power supply shall be capable of contributing to Voltage Control by continuous regulation of the Reactive Power supplied to the Distribution System.
- 5.4.6.2 The Embedded Generating Unit providing Ancillary Services for Reactive Power supply shall be fitted with a continuously acting automatic excitation control system to control the terminal voltage without instability over the entire operating range of the Embedded Generating Unit.
- 5.4.6.3 The performance requirements for excitation control facilities, including power System stabilizers, where necessary for System operations shall be specified in the Connection Agreement or Amended Connection Agreement.

5.4.7 Black Start Capability

- 5.4.7.1 The Generator shall specify in its application for a Connection Agreement or an Amended Connection Agreement if its Embedded Generating Unit has a Black Start capability.
- 5.4.7.2 The Embedded Generating Unit providing Ancillary Services for Black Start shall be capable of initiating a Black Start procedure in accordance with Section 7.7.4.

5.4.8 Fast Start Capability

- 5.4.8.1 The Generator shall specify in its application for a Connection Agreement or Amended Connection Agreement if its Embedded Generating Unit has a Fast Start capability.
- 5.4.8.2 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.

5.4.9 Protection Arrangements

- 5.4.9.1 The protection of 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.
- 5.4.9.2 The Distributor and the Embedded Generator shall be solely responsible for the protection System of the electrical Equipment and facilities at their respective sides of the Connection Point.

5.4.10 Transformer Connection and Grounding

5.4.10.1 The Distributor shall specify the transformer connection and grounding requirements for the transformer, in accordance with the provisions of Section 5.2.11.

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

5.5 REQUIREMENTS FOR DISTRIBUTION USERS

5.5.1 Requirements Relating to the Connection Point

5.5.1.1 The User's Equipment shall be connected to the Distribution System at a voltage level agreed to by the Distributor and the User based on the Distribution Impact Studies.

5.5.1.2 For a connection at Low Voltage, the Connection Point shall, in general, be at the User's Load side terminal of the metering equipment.

5.5.1.3 For a connection at Medium Voltage and High Voltage, the Connection Point arrangements shall be agreed upon by the Distributor and the User.

5.5.1.4 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.

5.5.1.5 Disconnect switches shall also be provided and arranged to isolate the Circuit Breaker for maintenance purposes.

5.5.2 Protection Arrangements

5.5.2.1 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.

5.5.2.2 The Distributor and the User shall be solely responsible for the protection System of electrical Equipment and facilities at their respective sides of the Connection Point.

5.5.2.3 The Distributor 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.

5.5.3 Transformer Connection and Grounding

The Distributor shall specify the connection and grounding requirements for the transformer, in accordance with the provisions of Section 5.2.11.

5.5.4 Underfrequency Relays for Automatic Load Dropping

5.5.4.1 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.

5.5.4.2 The Underfrequency Relays to be used in Automatic Load Dropping shall be fully digital with the following characteristics:

- (a) Frequency setting range: 57.0 to 62.0 Hz in steps of 0.1 Hz, preferably 0.05 Hz;
- (b) Adjustable time delay: 0 to 60 s in steps of 0.1 s;
- (c) Rate of Frequency setting range: 0 to ± 10 Hz/s in steps of 0.1 Hz/s;
- (d) Operating time delay: less than 0.1s;
- (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.

5.5.4.3 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.

5.5.4.4 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.

5.6 FIXED ASSET BOUNDARY DOCUMENT REQUIREMENTS

5.6.1 Fixed Asset Boundary Document

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

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

5.6.1.2 For the Fixed Asset Boundary Document referred to in item (a) above, the responsible management unit shall be shown, in addition to the Distributor 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 Distributor.

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

- (a) Equipment and their ownership;
- (b) Accountable Managers;
- (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.

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

5.6.2 Accountable Managers

5.6.2.1 Prior to the Completion Date specified in the Connection Agreement or Amended Connection Agreement, the User shall submit to the Distributor a list of Accountable Managers who are duly authorized to sign the Fixed Asset Boundary Documents on behalf of the User.

5.6.2.2 Prior to the Completion Date specified in the Connection Agreement or Amended Connection Agreement, the Distributor shall provide the User the name of the Accountable Manager who shall sign the Fixed Asset Boundary Documents on behalf of the Distributor.

5.6.2.3 Any change to the list of Accountable Managers shall be communicated to the other party at least six (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.

5.6.2.4 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.

5.6.3 Preparation of Fixed Asset Boundary Document

5.6.3.1 The Distributor shall establish the procedure and forms required for the preparation of the Fixed Asset Boundary Documents.

5.6.3.2 The User shall provide the information that will enable the Distributor to prepare the Fixed Asset Boundary Document, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

5.6.3.3 The Distributor shall prepare the Fixed Asset Boundary Documents for the Connection Point at least two (2) weeks prior to the Completion Date.

5.6.3.4 The Fixed Asset Boundary Document for the Equipment at the Connection Point shall include the details of the lines or cables emanating from the Distributor's and the User's sides of the Connection Point.

5.6.3.5 The date of issue and the issue number shall be included in every page of the Fixed Asset Boundary Document.

5.6.4 Signing and Distribution of Fixed Asset Boundary Document

5.6.4.1 Prior to the signing of the Fixed Asset Boundary Document, the Distributor shall send a copy of the completed Fixed Asset Boundary Document to the User, for any revision or for confirmation of its accuracy.

5.6.4.2 The Accountable Managers designated by the Distributor and the User shall sign the Fixed Asset Boundary Document, after confirming its accuracy.

5.6.4.3 Once signed but not less than two (2) weeks before the implementation date, the Distributor shall provide two (2) 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.

5.6.5 Modifications of an Existing Fixed Asset Boundary Document

5.6.5.1 When a User has determined that a Fixed Asset Boundary Document requires modification, it shall inform the Distributor at least eight (8) weeks before implementing the modification. The Distributor shall then prepare a revised Fixed Asset Boundary Document at least six (6) weeks before the implementation date of the modification.

5.6.5.2 When the Distributor has determined that a Fixed Asset Boundary Document requires modification, it shall prepare a revised Fixed Asset Boundary Document at least six (6) weeks prior to the implementation date of the modification.

5.6.5.3 If the Distributor or a User has determined that the Fixed Asset Boundary Document requires modification to reflect an emergency condition, the Distributor or the User, as the case may be, shall immediately notify the other party. The Distributor 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 seven (7) days after the conclusion of the meeting between the Distributor and the User, the Distributor shall provide the User a revised Fixed Asset Boundary Document.

5.6.5.4 The procedure specified in Section 5.6.4 for signing and distribution shall be applied to the revised Fixed Asset Boundary Document. The Distributor's notice shall indicate the revision, the new issue number, and the new date of issue.

5.7 ELECTRICAL DIAGRAM REQUIREMENTS

5.7.1 Responsibilities of the Distributor and Users

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

- 5.7.1.2 The User shall prepare and submit to the Distributor 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.
- 5.7.1.3 The Distributor shall provide the User with an Electrical Diagram for all the Equipment on the Distributor's side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.
- 5.7.1.4 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 Distributor shall prepare and distribute the composite Electrical Diagram for the entire Connection Point.

5.7.2 Preparation of Electrical Diagrams

- 5.7.2.1 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.
- 5.7.2.2 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.
- 5.7.2.3 The Electrical Diagrams shall be prepared using the Site and Equipment Identification prescribed in Article 7.12. The current status of the Equipment shall be indicated in the diagram. For example, a decommissioned switch bay shall be labeled "Spare Bay."
- 5.7.2.4 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.

5.7.3 Changes to Electrical Diagrams

- 5.7.3.1 If the Distributor or a User decides to add new Equipment or change an existing Equipment Identification, the Distributor or the User, as the case may be, shall provide the other party a revised Electrical Diagram, at least one (1) month prior to the proposed addition or change.
- 5.7.3.2 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.
- 5.7.3.3 The revised Electrical Diagram shall incorporate the new Equipment to be added, the existing Equipment to be replaced or the change in Equipment Identification.

5.7.4 Validity of Electrical Diagrams

- 5.7.4.1 The composite Electrical Diagram prepared by the Distributor or the User, in accordance with the provisions of Section 5.7.1, shall be the Electrical Diagram to be used for all operational and planning activities associated with the Connection Point.
- 5.7.4.2 If a dispute involving the accuracy of the composite Electrical Diagram arises, a meeting between the Distributor and the User shall be held as soon as possible, to resolve the dispute.

5.8 CONNECTION POINT DRAWING REQUIREMENTS

5.8.1 Responsibilities of the Distributor and Users

- 5.8.1.1 The Distributor shall specify the procedure and format to be followed in the preparation of the Connection Point Drawing for any Connection Point.
- 5.8.1.2 The User shall prepare and submit to the Distributor 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.
- 5.8.1.3 The Distributor shall provide the User with the Connection Point Drawing for the Distributor's side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.
- 5.8.1.4 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 Distributor shall prepare and distribute the composite Connection Point Drawing for the entire Connection Point.

5.8.2 Preparation of Connection Point Drawings

- 5.8.2.1 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.
- 5.8.2.2 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.
- 5.8.2.3 The Connection Point Drawing shall be prepared using the Site and Equipment Identification prescribed in Article 7.12. The current status of the Equipment shall be indicated in the drawing. For example, a decommissioned switch bay shall be labeled "Spare Bay."
- 5.8.2.4 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.

5.8.3 Changes to Connection Point Drawings

- 5.8.3.1 If the Distributor or a User decides to add new Equipment or change an existing Equipment Identification, the Distributor or the User, as the case may be, shall provide the other party a revised Connection Point Drawing, at least one (1) month prior to the proposed addition or change.
- 5.8.3.2 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.
- 5.8.3.3 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.
- 5.8.3.4 The Distributor 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.

5.8.4 Validity of the Connection Point Drawings

- 5.8.4.1 The composite Connection Point Drawing prepared by the Distributor or the User, in accordance with Section 5.8.1, shall be the Connection Point Drawing to be used for all operational and planning activities associated with the Connection Point.
- 5.8.4.2 If a dispute involving the accuracy of the composite Connection Point Drawing arises, a meeting between the Distributor and the User shall be held as soon as possible, to resolve the dispute.

5.9 DISTRIBUTION DATA REGISTRATION

5.9.1 Data to be Registered

- 5.9.1.1 The data relating to the Connection Point and the User Development that are submitted by the User to the Distributor shall be registered according to the following data categories:
 - (a) Forecast Data;
 - (b) Estimated Equipment Data; and
 - (c) Registered Equipment Data.
- 5.9.1.2 The Forecast Data, including Demand and Active Energy, shall contain the User's best estimate of the data being projected for the five (5) succeeding years.
- 5.9.1.3 The Estimated Equipment Data shall contain the User's best estimate of the values of parameters and information about the Equipment for the five (5) succeeding years.

5.9.1.4 The Registered Equipment Data shall contain validated actual values of parameters and information about the Equipment that are submitted by the User to the Distributor 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.

5.9.2 Stages of Data Registration

5.9.2.1 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 (3) stages and classified accordingly as:

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

5.9.2.2 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 6.4, and the Detailed Planning Data specified in Article 6.5, when required ahead of the schedule specified in the Connection Agreement or Amended Connection Agreement.

5.9.2.3 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.

5.9.2.4 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 5.9.1 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.

5.9.3 Data Forms

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

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CHAPTER 6

DISTRIBUTION PLANNING

6.1 PURPOSE AND SCOPE

6.1.1 Purpose

- (a) To specify the responsibilities of the Distributor, the Distribution System Users, and the Distribution Planning Subcommittee 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 Distributor in planning the development of the Distribution System.

6.1.2 Scope of Application

This Chapter applies to all Distribution System Users including:

- (a) Distributors;
- (b) Embedded Generators;
- (c) Users; and
- (d) Any other entity with a User System connected to the Distribution System.

6.2 DISTRIBUTION PLANNING RESPONSIBILITIES AND PROCEDURES

6.2.1 Distribution Planning Responsibilities

6.2.1.1 The Distributor 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.

6.2.1.2 The Users of the Distribution System, including Embedded Generators, Large Customers, and other entities that have a System connected to the Distribution System shall cooperate with the Distributor in maintaining a Distribution Planning data bank and in advising the Distribution Planning Subcommittee on improved Distribution Planning procedures.

6.2.1.3 The Distribution Planning Subcommittee shall be responsible for:

- (a) Evaluating and making recommendations on the Distribution Development Plan to the DMC;
- (b) Evaluating and recommending actions on proposed major Distribution System reinforcement and expansion projects; and
- (c) Periodically reviewing and recommending changes in planning procedures and standards.

6.2.2 Submission of Planning Data

- 6.2.2.1 Any User applying for connection or a modification of an existing connection to the Distribution System shall submit to the Distributor the relevant Standard Planning Data specified in Article 6.4 and the Detailed Planning Data specified in Article 6.5, in accordance with the requirements prescribed in Article 5.3.
- 6.2.2.2 All Users shall submit annually to the Distributor the relevant historical planning data for the previous year and the forecast planning data for the five (5) succeeding years by calendar week 23 of the current year. These shall include the updated Standard Planning Data and the Detailed Planning Data.
- 6.2.2.3 The required Standard Planning Data specified in Article 6.4 shall consist of information necessary for the Distributor to evaluate the impact of any User Development on the Distribution System.
- 6.2.2.4 The Detailed Planning Data specified in Article 6.5 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 Distributor to assess any implication associated with the Connection Points.
- 6.2.2.5 The Standard Planning Data and Detailed Planning Data shall be submitted by the User to the Distributor according to the following categories:
 - (a) Forecast Data;
 - (b) Estimated Equipment Data; and
 - (c) Registered Equipment Data.
- 6.2.2.6 The Forecast Data shall contain the User's best estimate of the data, including Energy and Demand, being projected for the five (5) succeeding years.
- 6.2.2.7 The Estimated Equipment Data shall contain the User's best estimate of the values of parameters and information pertaining to its Equipment.
- 6.2.2.8 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 Distributor at the time of connection.

6.2.3 Consolidation and Maintenance of Planning Data

6.2.3.1 The Distributor 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.

6.2.3.2 If there is any change to its planning data, the User shall notify the Distributor 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.

6.2.4 Evaluation of Proposed Development

6.2.4.1 The Distributor shall conduct Distribution Impact Studies to assess the effect of the proposed User Development on the Distribution System and the System of other Users.

6.2.4.2 The Distributor shall notify the User of the results of the Distribution Impact Studies.

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

6.2.5 Preparation of Distribution Development Plan

6.2.5.1 The Distributor 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).

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

6.2.5.3 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.

6.2.5.4 If a User believes that the cohesive forecast prepared by the Distributor does not accurately reflect its assumptions on the planning data, it shall

promptly notify the Distributor of its concern. The Distributor and the User shall promptly meet to address the concern of the User.

6.3 DISTRIBUTION PLANNING STUDIES

6.3.1 Distribution Planning Studies to be Conducted

6.3.1.1 The Distributor shall conduct Distribution planning studies to ensure the safety and Reliability of the Distribution System for the following:

- (a) Preparation of the Distribution Development Program 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.

6.3.1.2 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.

6.3.1.3 The relevant technical studies described in Sections 6.3.2 to 6.3.5 and the required planning data specified in Articles 6.4 and 6.5 shall be used in the conduct of the Distribution Planning studies.

6.3.1.4 The Distributor shall conduct distribution planning analysis which shall include:

- (a) The determination of optimum patterns for the selection of sites and sizes of distribution substation;
- (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.

6.3.1.5 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.

6.3.2 Voltage Drop Studies

6.3.2.1 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.

6.3.2.2 Voltage drop Studies shall be performed to evaluate the impact on the Distribution System of the connection of new Embedded Generating Plants, Loads, or distribution lines.

6.3.3 Short Circuit Studies

6.3.3.1 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.

6.3.3.2 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. 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.

6.3.3.3 The Distributor and the User shall exchange information on fault infeed levels at the Connection Point. This 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.

6.3.3.4 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 Equipment and the proposed Distribution System configurations are suitable for flexible and safe operation.

6.3.4 System Loss Studies

6.3.4.1 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.

6.3.4.2 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.

6.3.5 Distribution Reliability Studies

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

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

6.4 STANDARD PLANNING DATA

6.4.1 Energy and Demand Forecast

- 6.4.1.1 The User shall provide the Distributor with its Energy and Demand forecasts at each Connection Point for the five (5) succeeding years.
- 6.4.1.2 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.
- 6.4.1.3 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.
- 6.4.1.4 The following factors shall be taken into account by the Distributor 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 Distributors; and
 - (g) Other relevant factors.
- 6.4.1.5 The Embedded Generator shall submit to the Distributor the projected Energy and Demand to be generated by each Embedded Generating Unit and Embedded Generating Plant.

6.4.2 Embedded Generating Unit Data

- 6.4.2.1 The Embedded Generator shall provide the Distributor with data relating to the Embedded Generating Units of each Embedded Generating Plant.
- 6.4.2.2 The following information shall be provided for the Embedded Generating Units of each 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.
- 6.4.2.3 If the 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.

6.4.3 User System Data

6.4.3.1 If the User is to be connected at Low Voltage, the following data shall be provided to the Distributor:

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

6.4.3.2 If the User is to be connected at Medium Voltage or High Voltage, the following data shall be provided to the Distributor:

- (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.

6.4.3.3 The User shall provide the Electrical Diagrams and Connection Point Drawings of the User System and the Connection Point, as specified in Articles 5.7 and 5.8, 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.

6.4.3.4 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}).

6.4.3.5 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).
- 6.4.3.6 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).
- 6.4.3.7 The User shall provide the details of its System Grounding. This shall include the rated capacity and impedances of the Grounding Equipment.
- 6.4.3.8 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).
- 6.4.3.9 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.
- 6.4.3.10 If the User has an Embedded Generating Plant and/or significantly large motors, the short circuit contributions of the Embedded 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 IEC Standards or their equivalent national standards.

6.5 DETAILED PLANNING DATA

6.5.1 Embedded Generating Unit and Embedded Generating Plant Data

- 6.5.1.1 The following additional information shall be provided for the Embedded Generating Units of each 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 (amps) at rated MW and MVAR output and at rated terminal voltage; and
- (l) Short circuit and open circuit characteristic curves.

6.5.1.2 The following information on Step-up Transformers shall be provided for each Embedded Generating Unit:

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

6.5.1.3 The following excitation control system parameters shall be submitted:

- (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.

6.5.1.4 The following speed-governing parameters for reheat steam Generating Units shall be submitted:

- (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.
- 6.5.1.5 The following speed-governing parameters for non-reheat steam, gas turbine, geothermal, and hydro Generating Units shall be submitted:
- (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.
- 6.5.1.6 The following plant flexibility performance data for each Generating Plant shall be submitted:
- (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.
- 6.5.1.7 The following auxiliary Demand data shall be submitted:
- (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.

6.5.2 User System Data

6.5.2.1 Large Customers and other Distributors connected to the Distribution System shall submit to the Distributor the following load characteristics:

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

6.5.2.2 The Distributor 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.

6.5.2.3 The User shall provide any additional planning data that may be requested by the Distributor.

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CHAPTER 7

DISTRIBUTION OPERATIONS

7.1 PURPOSE AND SCOPE

7.1.1 Purpose

- (a) To define the operational responsibilities of the Distributor and all Distribution System Users;
- (b) To specify the operational arrangements for mutual assistance, Equipment and inventory sharing, and joint purchases among Distributors;
- (c) To specify the requirements for communication and the notices to be issued by the Distributor to Users and the notices to be issued by Users to the Distributor 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 Distributor 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.

7.1.2 Scope of Application

This Chapter applies to the following:

- (a) Distributors;
- (b) Other Distributors connected to the Distribution System;
- (c) Embedded Generators (greater than or equal to one (1) MVA output);

- (d) Large Customers; and
- (e) Other Users receiving unbundled service.

7.2 OPERATIONAL RESPONSIBILITIES

7.2.1 Operational Responsibilities of the Distributor

- 7.2.1.1 The Distributor 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.
- 7.2.1.2 The Distributor is responsible for preparing the Distribution Maintenance Program for the maintenance of its Equipment and facilities.
- 7.2.1.3 The Distributor is responsible for providing and maintaining all Distribution Equipment and facilities.
- 7.2.1.4 The Distributor is responsible for designing, installing, and maintaining a distribution protection that will ensure the timely disconnection of faulted facilities and Equipment.
- 7.2.1.5 The Distributor is responsible for ensuring that safe and economic distribution operating procedures are always followed.
- 7.2.1.6 The Distributor is responsible for maintaining an Automatic Load Dropping scheme, as necessary, to meet the targets agreed to with the System Operator.
- 7.2.1.7 The Distributor is responsible for developing and proposing Distribution Wheeling Charges to the ERC.

7.2.2 Operational Responsibilities of Embedded Generators

- 7.2.2.1 The Embedded Generator is responsible for ensuring that its Generating Units can deliver the capabilities declared in its Connection Agreement or Amended Connection Agreement.
- 7.2.2.2 The Embedded Generator is responsible for providing accurate and timely planning and operations data to the Distributor.
- 7.2.2.3 The Embedded Generator is responsible for executing the instructions of the Distributor during emergency conditions.

7.2.3 Operational Responsibilities of Other Distribution Users

- 7.2.3.1 The User is responsible for assisting the Distributor in maintaining Power Quality in the Distribution System during normal conditions by correcting any User facility that causes Power Quality problems.
- 7.2.3.2 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.

- 7.2.3.3 The User is responsible for executing the instructions of the Distributor during emergency conditions.

7.3 OPERATIONAL ARRANGEMENTS

7.3.1 Mutual Assistance

- 7.3.1.1 The Distribution Technical Standards Subcommittee shall recommend emergency procedures to the DMC and the Distributors, including the development of a mutual assistance program for Distributors.
- 7.3.1.2 The Distributors shall cooperate in the establishment of mutual assistance procedures and in providing coordinated responses during emergencies.

7.3.2 Equipment and Inventory Sharing

- 7.3.2.1 The Distribution Technical Standards Subcommittee shall recommend procedures for Equipment and inventory sharing to the DMC and the Distributors, including the development of an Equipment and inventory sharing program for Distributors.
- 7.3.2.2 The Distributors 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.

7.3.3 Joint Purchases

- 7.3.3.1 The Distribution Technical Standards Subcommittee shall recommend procedures for joint purchase arrangements to the DMC and the Distributors, including the development of a joint purchase program for Distributors.
- 7.3.3.2 The Distributors 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.

7.4 DISTRIBUTION OPERATIONS COMMUNICATIONS, NOTICES, AND REPORTS

7.4.1 Distribution Operations Communications

- 7.4.1.1 The Distributor and the User shall establish a communication channel for the exchange of information required for distribution operation. The communication channel shall, as much as possible, be direct between the Distributor and the User.
- 7.4.1.2 If the Distributor decides that a back up or alternative route of communication and/or emergency communication is necessary for the safe operation of the Distribution System, the additional means of communication shall be agreed between the Distributor and the User.
- 7.4.1.3 A list of duly authorized personnel and their telephone numbers shall be exchanged between the Distributor and the User so that control activities can

be efficiently coordinated. The Distributor and the User shall maintain 24-hour availability for these duly authorized personnel when necessary.

7.4.2 Distribution Operations Notices

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

7.4.2.2 A Planned Activity Notice shall be issued by a User to the Distributor for any planned activity such as a planned Shutdown or Scheduled Maintenance of its Equipment at least three (3) days prior to the actual Shutdown or maintenance.

7.4.3 Distribution Operations Reports

7.4.3.1 The Distributor 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 Distributor to address them, and the recommendations to prevent their recurrence in the future.

7.4.3.2 The Distributor shall submit to the DMC the Significant Incident Reports prepared pursuant to the provisions of Section 7.7.2.

7.4.3.3 The Distributor 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.

7.5 DISTRIBUTION MAINTENANCE PROGRAM

7.5.1 Preparation of Maintenance Program

7.5.1.1 The Distributor 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;

7.5.1.2 The three-year Maintenance Program shall be prepared annually for the three (3) 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.

7.5.1.3 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 factor.

7.5.2 Submission and Approval of Maintenance Program

7.5.2.1 The User shall provide the Distributor by week 23 of the current year a provisional Maintenance Program for the three (3) succeeding years. The following information shall be included in the User's provisional Maintenance Program or 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.

7.5.2.2 The Maintenance Program submitted by the Embedded Generator for its Scheduled Generating Units shall be submitted by the Distributor to the Grid Owner by week 27 pursuant to the requirement of the Philippine Grid Code.

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

7.5.2.4 The Distributor shall provide the User a written copy of the User's approved Maintenance Program.

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

7.6 DEMAND AND VOLTAGE CONTROL

7.6.1 Demand Control Coordination

7.6.1.1 The Distributor 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.

7.6.1.2 The Demand Control to be implemented by the Distributor shall include the following:

- (a) Automatic Load Dropping;
- (b) Manual Load Dropping;
- (c) Demand Disconnection initiated by Users; and
- (d) Voluntary Load Curtailment.

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

7.6.1.4 If the Demand Control is to be undertaken by the Distributor to safeguard its Distribution System, the Distributor shall coordinate the Demand Control with the affected Users.

7.6.1.5 The Distributor 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 two (2) minutes after the instruction is given by the System Operator.

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

7.6.2 Automatic Load Dropping

7.6.2.1 The System Operator shall establish the level of Demand required for Automatic Load Dropping in order to limit the consequences of 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.

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

7.6.2.3 The underfrequency Disconnection scheme shall be designed to allow the Demand Reduction to be uniformly applied throughout the Distribution System, taking into account any operational requirements and essential loads.

7.6.2.4 To ensure that a subsequent fall in frequency will be contained by the operation of ALD, additional Manual Load Dropping shall be implemented by the Distributor so that the loads that were dropped by ALD can be reconnected.

7.6.2.5 The Distributor shall exert best effort to restore immediately the critical facilities included in the ALD program.

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

7.6.3 Manual Load Dropping

- 7.6.3.1 The Distributor shall make arrangements that will enable it to disconnect its Customers immediately following the issuance by the System Operator of an instruction to implement Manual Load Dropping.
- 7.6.3.2 The Distributors shall, in consultation with the System Operator, establish a priority scheme for Manual Load Dropping based on equitable load allocation.
- 7.6.3.3 If the Distributor disconnected a User System, the User shall not reconnect its System until instructed by the Distributor to do so.

7.6.4 Demand Control Initiated by a User

- 7.6.4.1 If a User intends to implement for the following day Demand Control through a Demand Disconnection at the Connection Point, it shall notify the Distributor 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.
- 7.6.4.2 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 Loads for a certain period of time depending on the extent of the generation deficiency. Industrial Customers who implemented a VLC shall provide the Distributor with the amount of Demand reduction actually achieved through the VLC scheme.

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

7.7 EMERGENCY PROCEDURES

7.7.1 Preparation for Distribution Emergencies

- 7.7.1.1 The Distributor 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.
- 7.7.1.2 The User shall provide the Distributor, in writing, the telephone numbers of persons who can make binding decisions when there is a Significant Incident.
- 7.7.1.3 The Distributor shall develop and maintain a Manual of Distribution Emergency Procedures, which lists all parties to be notified, including their business and home phone numbers, in case of an emergency.
- 7.7.1.4 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.
- 7.7.1.5 The User shall participate in all emergency drills organized by the Distributor.

7.7.2 Significant Incident Procedures

- 7.7.2.1 Following the issuance of a Significant Incident Notice by the Distributor or a User, any User may file a written request to the Distributor for a joint investigation of the Significant Incident. If there have been several Significant Incidents, the joint investigation may include the other Significant Incidents.
- 7.7.2.2 A joint investigation of the Significant Incident shall be conducted only when the Distributor and the Users have reached an agreement to conduct the joint investigation.
- 7.7.2.3 The Distributor shall submit a written report to the DMC and the ERC detailing all the information, findings, and recommendations regarding the Significant Incident.
- 7.7.2.4 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.

7.7.3 Operation of Embedded Generating Unit in Island Grid

- 7.7.3.1 If a part of the Distribution System to which an Embedded Generating Unit is connected becomes isolated from the Distribution System, the Distributor shall decide if it is desirable for the Embedded Generating Unit to continue operating.
- 7.7.3.2 If no facilities exist for the subsequent resynchronization with the rest of the Distribution System, the Distributor shall issue an instruction to the Embedded Generator to disconnect its Embedded Generating Unit so that the Island Grid may be reconnected to the rest of the Distribution System.

7.7.4 Black Start and Resynchronization Procedures

- 7.7.4.1 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 Distributor shall initiate a Black Start procedure upon instruction by the System Operator.
- 7.7.4.2 The System Operator, pursuant to the procedures in the 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.

7.8 SAFETY COORDINATION**7.8.1 Safety Coordination Procedures**

- 7.8.1.1 The Distributor 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 Distributor and the User shall govern any work or testing on the Distribution System or the User System.
- 7.8.1.2 The Distributor 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.
- 7.8.1.3 The User shall furnish the Distributor a copy of its Safety Rules and Local Safety Instructions relating to the Safety Precautions on its MV and HV Equipment.
- 7.8.1.4 Any party who wants to revise any provision of its Local Safety Instructions shall provide the other party a written copy of the revisions.
- 7.8.1.5 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 on the Distribution System or the User System.
- 7.8.1.6 Work or testing on any Equipment at the Connection Point shall be carried out only in the presence of the representatives of the Distributor and the User.

- 7.8.1.7 The User (or the Distributor) shall seek authority from the Distributor (or the User) if it wishes to access any Distributor's (or User's) Equipment.
- 7.8.1.8 If work or testing is to be carried out on the Distribution System and a Safety Precaution is required on the MV and HV Equipment of several Users, the Distributor shall ensure that the Safety Precautions on the Distribution System and on the System of all Users involved are coordinated and implemented.
- 7.8.1.9 If work or testing is to be carried out on the Distribution System and a User becomes aware that Safety Precautions are also required on the System of other Users, the Distributor shall be promptly informed of the required Safety Precautions on the System of the other Users. The Distributor shall ensure that Safety Precautions are coordinated and implemented on the Distribution System and the Systems of the affected Users.

7.8.2 Safety Coordinator

- 7.8.2.1 The Distributor 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.
- 7.8.2.2 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.
- 7.8.2.3 If work or testing is to be carried out on 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.
- 7.8.2.4 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.
- 7.8.2.5 If a Safety Precaution becomes ineffective, the concerned Safety Coordinator shall inform the other Safety Coordinators about it without delay stating the reasons why the Safety Precaution has lost its integrity.

7.8.3 Safety Logs and Record of Inter-System Safety Precautions

- 7.8.3.1 The Distributor 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 one (1) year.
- 7.8.3.2 The Distributor 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.

7.8.4 Location of Safety Precautions

7.8.4.1 When work or testing is to be carried out on the Distribution System (or the User System) and Safety Precautions are required on the User System (or the Distribution System), the Requesting Safety Coordinator shall contact the concerned Implementing Safety Coordinator to agree on the locations at which 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.

7.8.4.2 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 7.12; and
- (b) The means of implementing Isolation as specified in Section 7.8.5.

7.8.4.3 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 7.12; and
- (b) The means of implementing Grounding as specified in Section 7.8.5.

7.8.4.4 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.

7.8.5 Implementation of Safety Precautions

7.8.5.1 Once the locations of Isolation and Grounding have been agreed upon, the Implementing Safety Coordinator shall ensure that the Isolation is implemented.

7.8.5.2 The Isolation shall be implemented by any of the following:

- (a) A disconnect switch 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 Distributor 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 Distributor or of the User. In addition, a Safety Tag shall be placed at the switching points.

7.8.5.3 The Implementing Safety Coordinator, after the required Isolation in all locations had been established on his System, shall notify the Requesting Safety Coordinator that the required Isolation has been implemented.

7.8.5.4 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.

7.8.5.5 The Implementing Safety Coordinator shall ensure the implementation of Grounding and notify the Requesting Safety Coordinator that Grounding has been established on his System.

7.8.5.6 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 Distributor 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 Distributor or those of the User. In addition, a Safety Tag shall be placed at the point of connection and all related switching points.

7.8.5.7 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.

7.8.6 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.

7.8.7 Cancellation of Safety Precautions

7.8.7.1 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.

7.8.7.2 Both coordinators shall then cancel the Safety Precautions.

7.9 DISTRIBUTION TESTING AND MONITORING

7.9.1 Testing Requirements

- 7.9.1.1 The Distributor shall, from time to time, determine the need to test and/or monitor the Power Quality at various points on its Distribution System.
- 7.9.1.2 The requirement for specific testing and/or monitoring by a Distributor shall be initiated by the receipt of a complaint relating to Power Quality in the Distribution System.
- 7.9.1.3 In certain situations, the Distributor may require the testing and/or monitoring to take place at the Connection Point of a User to be witnessed by a User representative.
- 7.9.1.4 If testing and/or monitoring is required at the Connection Point, the Distributors shall advise the User involved and shall make available the results of such tests to the User.
- 7.9.1.5 Upon the request of the User, a retest shall be carried out. The cost of the retest shall be charged to the User.
- 7.9.1.6 If the results of the test show that the User is operating outside the technical parameters specified in Sections 5.2.5, 5.2.6, and 5.2.7, the User shall be informed accordingly. The User shall rectify the situation within a period time as agreed upon with the Distributor.
- 7.9.1.7 If the User failed to rectify the situation, the Distributor may disconnect the User from the Distribution System, in accordance with the Connection Agreement or Amended Connection Agreement.

7.9.2 Monitoring of User Effect on the Distribution System

- 7.9.2.1 The Distributor shall, from time to time, monitor the effect of the User System on the Distribution System.
- 7.9.2.2 The monitoring shall normally be related to the amount of Active Power and Reactive Power transferred across the Connection Point.
- 7.9.2.3 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 Distributors shall inform the User. Upon the request of the User, the Distributor shall demonstrate the results of such monitoring.
- 7.9.2.4 The User may request technical information on the method of monitoring and, if necessary, request another method that is acceptable to the Distributor.
- 7.9.2.5 If the User is operating outside the limits specified in Sections 5.2.5, 5.2.6, and 5.2.7, 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.

- 7.9.2.6 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.

7.10 SYSTEM TEST

7.10.1 System Test Requirements

- 7.10.1.1 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.
- 7.10.1.2 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.
- 7.10.1.3 Where the System Test may have an impact on the Grid, the procedure specified in the Grid Code shall be used in carrying out the proposed System Test.

7.10.2 System Test Request

- 7.10.2.1 If a User wishes to undertake a System Test on its System, it shall submit to the Distributor 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.
- 7.10.2.2 The System Test Proponent shall provide sufficient time for the Distributor to plan the proposed System Test. The Distributor shall determine the time required for each type of System Test.
- 7.10.2.3 The Distributor 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.
- 7.10.2.4 The Distributor shall determine and notify other Users, other than the System Test Proponent, that may be affected by the proposed System Test.
- 7.10.2.5 The Distributor may also initiate a System Test if it has determined that the System Test is necessary to ensure the safety and Reliability of the Distribution System.

7.10.3 System Test Group

- 7.10.3.1 If the Distributor is the System Test Proponent, it shall notify all affected Users of the proposed System Test. If the Distributor is not the System Test Proponent, it shall notify, within one (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 7.8.

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

7.10.3.3 The Distributor 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 Distributor or the System Test Proponent.

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

7.10.3.5 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.

7.10.3.6 The Distributor, the System Test Proponent (if it is not the Distributor) 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.

7.10.4 System Test Program

- 7.10.4.1 Within two (2) months after the first meeting and at least one (1) month prior to the date of the proposed System Test, the System Test Group shall submit to the Distributor, the System Test Proponent (if it is not the Distributor), 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.
- 7.10.4.2 If the proposed System Test Program is acceptable to the Distributor, 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.
- 7.10.4.3 If the System Test Group is unable to develop a System Test Program or reach a decision in implementing the System Test Program, the Distributor shall determine whether it is necessary to proceed with the System Test to ensure the safety and Reliability of the Distribution System.
- 7.10.4.4 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 Distributor, 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.
- 7.10.4.5 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.

7.10.5 System Test Report

- 7.10.5.1 Within two (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 Distributor, the affected Users, and the members of the System Test Group.
- 7.10.5.2 After the submission of System Test Report, the System Test Group shall be automatically dissolved.

- 7.10.5.3 The Distributor shall submit the System Test Report to the DMC for its review and recommendations.

7.11 EMBEDDED GENERATING UNIT CAPABILITY TESTS

7.11.1 Test Requirements

- 7.11.1.1 Tests shall be conducted, in accordance with the agreed procedures and standards, to confirm the compliance of 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 Grid Code and the Distribution Code;
 - (c) Capability to deliver the Ancillary Services that the Generator had agreed to provide; and
 - (d) Availability of Generating Units in accordance with their capability declaration.
- 7.11.1.2 All tests shall be recorded and witnessed by the authorized representatives of the Distributor, Generator, and/or User.
- 7.11.1.3 The Generator shall demonstrate to the Distributor the reliability and accuracy of the test instruments and Equipment to be used in the test.
- 7.11.1.4 The Distributor may at any time issue instructions requiring tests to be carried out on any 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.
- 7.11.1.5 If an Embedded Generating Unit fails the test, the Generator shall correct the deficiency within an agreed period to attain the relevant registered parameters for that Embedded Generating Unit.
- 7.11.1.6 Once the Generator achieves the registered parameters of its Embedded Generating Unit that previously failed the test, it shall immediately notify the Distributor. The Distributor shall then require the Generator to conduct a retest in order to demonstrate that the appropriate parameter has already been restored to its registered value.
- 7.11.1.7 If a dispute arises relating to the failure of an Embedded Generating Unit to pass a given test, the Distributor, the Generator, and/or User shall seek to resolve the dispute among themselves.
- 7.11.1.8 If the dispute cannot be resolved, one of the parties may submit the issue to the DMC.

7.11.2 Tests to be Performed

- 7.11.2.1 The Reactive Power test shall demonstrate that the Embedded Generating Unit meets the registered Reactive Power Capability requirements specified in Section 5.4.2. The Embedded Generating Unit shall pass the test

- if the measured values are within ± 5 percent of the Capability as registered with the Grid Owner through the Distributor.
- 7.11.2.2 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 5.4.8. The Embedded Generating Unit shall pass the test if it meets the Fast Start capability requirements.
- 7.11.2.3 The Black Start test shall demonstrate that the Embedded Generating Plant with Black Start capability can implement a Black Start procedure, as specified in Section 5.4.7. 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.
- 7.11.2.4 The Declared Data capability test 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.
- 7.11.2.5 The Dispatch accuracy test shall demonstrate that the Embedded Generating Unit meets the relevant Generation 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 Generation 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 Generation Scheduling and Dispatch Parameters, values are within $\pm 1.5\%$ of the declared values.
- 7.11.2.6 The Ancillary Services acceptability test shall determine the committed services in terms of parameter quantity or volume, timeliness, and other operational requirements. Generators providing Ancillary Services shall conduct the test or define the committed service. However, monitoring by the System Operator or the Distributor of the Ancillary Services performance in response to System-derived inputs shall also be carried out.

7.12 SITE AND EQUIPMENT IDENTIFICATION

7.12.1 Site and Equipment Identification Requirements

- 7.12.1.1 The Distributor 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.

7.12.1.2 The identification for the Site shall include and be unique for each substation and switchyard where a Connection Point is located.

7.12.1.3 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.

7.12.2 Site and Equipment Identification Label

7.12.2.1 The Distributor shall develop and establish a standard labeling system, which specifies the dimension, sizes of characters, and colors of labels, to identify the Sites and Equipment.

7.12.2.2 The Distributor 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 8

DISTRIBUTION REVENUE METERING REQUIREMENTS*

8.1 PURPOSE AND SCOPE

8.1.1 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; and
- (c) To ensure that a dispute settlement process is established and maintained to quickly and satisfactorily resolve any billing and payment dispute.

8.1.2 Scope of Application

This Chapter applies to all Distribution System Participants including:

- (a) Distributors;
- (b) Other Distributors connected to the Distribution System;
- (c) Embedded Generators;
- (d) Large Customers; and
- (e) Other Users receiving unbundled services.

8.1.3 Exemptions

Users receiving bundled service from the Distributor shall be exempted from the provisions required for Users who are receiving unbundled service. These exemptions are noted in the relevant Sections of this Chapter.

8.2 UNBUNDLED SERVICE PROVISIONS

8.2.1 Electricity Service From Supplier

The Act allows End-Users belonging to the contestable market to obtain power from electrical Suppliers authorized by the ERC. The Supplier may be a member of the WESM, another Distributor, or an Embedded Generator.

8.2.2 Procedure for Collection of Metering Data, Billing, and Settlement

If the Supplier is a member of the WESM, the Distributor shall take delivery of any such power services at its Connection Point with the Grid and deliver those services to the End-Users. The Distributor shall develop a procedure for the collection of metering data, billing, and settlement consistent with the Market Rules of the WESM.

* Note: This Chapter will be revised based on the provisions of the Market Rules.

This procedure shall apply even if the Supplier is an Embedded Generator in order to streamline the billing process and reduce administrative burden.

8.3 METERING REQUIREMENTS

8.3.1 Metering Equipment

The metering Equipment at the Connection Point 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 blocks, loading resistors, meter cubicle, security seals, etc.; and
- (d) Optional Integrating Pulse Recorder, time source, and backup battery.

8.3.2 Metering Responsibility

8.3.2.1 The Distributor shall 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.

8.3.2.2 The supply and installation of the metering Equipment shall be agreed upon by both parties in the Connection Agreement or Amended Connection Agreement. The Distributor shall ensure that the metering equipment is provided, installed, operated, maintained, and tested in accordance with this Chapter. The Distributor and User shall also ensure that the requirements of this Chapter regarding access to metering Equipment by other authorized parties are complied with.

8.3.3 Active Energy and Demand Metering

8.3.3.1 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.

8.3.3.2 The meter pulses may be required to be made available to allow separate recording of the input and/or output Active Energy and Active Power at each Connection Point.

8.3.3.3 Active and Reactive Energy and Demand metering shall be provided for each User at each Connection Point and shall be accessible for inspection and reading. If the metering cannot be installed at the Connection Point due to the Distribution System's design construction or for other reasons, the metering shall be installed as close as possible to the Connection Point. In this case, a procedure shall be established to account for the Energy loss between the Connection Point and point of metering.

8.3.4 Reactive Energy and Demand Metering

8.3.4.1 This is a requirement at all Connection Points in which an input and/or output Connection Agreement exists between Distributor and any User

wherein the User has an input and/or output Reactive Energy and Reactive Power. It is also a requirement for any User receiving unbundled services.

8.3.4.2 The Reactive Energy and Demand metering 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.

8.3.4.3 The meter pulses may be made available to allow separate recording of the input and/or output Reactive Energy and Demand at each Connection Point.

8.3.5 Integrating Pulse Meters

8.3.5.1 An Integrating Pulse Meter shall be provided at every Connection Point to record active and reactive integrated Demand data for use in billing and settlement for unbundled energy services. This requirement can be considered as a preferred option for bundled services.

8.3.5.2 The Integrating Pulse Meter at the Connection Point of a User receiving unbundled energy services shall be capable of electronic downloading of stored data or manual on-site interrogation of data by the Distributor.

8.3.5.3 The Integrating Pulse Meter shall have fail safe storage for at least two months of integrated Demand data and must be capable of retaining readings and time of day at least two (2) days without an external power source.

8.4 METERING EQUIPMENT STANDARDS

8.4.1 Voltage Transformers

All voltage Transformers shall comply with the IEC Standards or their equivalent national standards for metering and shall have an accuracy class of 0.3 or better. The burden in each phase of the voltage Transformer shall not exceed the specified burden of the said voltage Transformer. It shall be connected only to a revenue meter with a burden that will not affect the accuracy of the measurement.

8.4.2 Current Transformers

All current Transformers shall comply with the IEC Standards or their equivalent national standards for metering and shall have an accuracy class of 0.3 or better. The burden in each phase of the current Transformer shall not exceed the specified burden of the said current Transformer. It shall be connected only to a revenue meter with a burden that will not affect the accuracy of the measurement.

8.4.3 Meters

8.4.3.1 The meter shall conform to the type of circuit of the Distribution System where it is connected. The meter shall measure and locally display the kW, kWh, kVAR, kVARh, and cumulative demand with the optional features of time-of-use, maintenance records, and pulse output.

8.4.3.2 A cumulative record of the parameters measured shall be available on the meter. Bidirectional meters shall have two such records available. If combined

Active and Reactive Energy meters are provided, then a separate record shall be provided for each measured quantity and direction. For electronic meters, the loss of auxiliary supply shall not erase these records.

- 8.4.3.3 Required for unbundled services and optional for bundled services, pulse output shall be provided for each measured quantity. The pulse output shall be from a three-wire terminal with pulse duration of the range 40–80 milliseconds (preferably selectable) and with selective pulse Frequency or rate. The pulse output shall be galvanically isolated from the voltage and current transformers being measured and from the auxiliary supply input terminals.

8.4.4 Integrating Pulse Recorders Required for Unbundled Service

- 8.4.4.1 Integrating pulse recorders required for unbundled service shall be capable of recording integrated Demand periods adjustable between 15 minutes and 60 minutes.
- 8.4.4.2 The integrating pulse recorder shall be capable of electronic data transfer through telephone lines or the Distributor's communication channel or manual on-site interrogation of stored data.
- 8.4.4.3 The integrating pulse recorder shall provide a record for reference at a future time. The record shall be suitable for reference for a period of one (1) year after it was generated. The integrating pulse recorder shall be regularly interrogated and the record be maintained at the recorder for two (2) complete billing periods between one (1) interrogation or 60 days, whichever is longer.
- 8.4.4.4 The time reference used with the Demand recorder shall ensure that the Demand period accuracy of this integrating pulse recorder is with a time error of no more than +/-60 seconds.
- 8.4.4.5 All revenue metering installations shall record time based on Philippine standard time.
- 8.4.4.6 The start of each demand period shall be within +/-60 seconds of standard time.
- 8.4.4.7 Reprogramming of the integrating pulse recorder shall be done as soon as possible within one billing cycle if there is a time error.
- 8.4.4.8 The pulse from two or more meters may be combined into one integrating pulse recorder provided all the requirements of this Chapter are met.

8.4.5 Other Accessories

- 8.4.5.1 The metering Equipment 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.
- 8.4.5.2 All wiring from the instrument transformers' secondary terminal box to the metering Equipment cubicle shall be placed in a rigid conduit.

8.4.5.3 The ERC (or the party authorized by ERC) in the presence of the legal and authorized representatives of the Distributor and the User shall seal meters and its accessories. All seals placed or removed on metering System shall be recorded and the record signed by both parties and the ERC representative.

8.5 METERING EQUIPMENT TESTING AND MAINTENANCE

8.5.1 Instrument Transformer Testing

Test on the Instrument Transformers shall be conducted by the authorized representatives of the Distributor 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. The tests shall be carried out in accordance with the practices of the Distributor or an agreed equivalent international standard or guidelines set out by the ERC.

8.5.2 Meter Testing and Calibration

Test and calibration of meters shall be conducted by the ERC (or its authorized representative) in the presence of the authorized representatives of the Distributor and the User during the Test and Commissioning stage and as the need arises. If both parties cannot agree on the accuracy of the meter, the ERC shall act as arbiter.

8.5.3 Maintenance of Metering Equipment

The Distributor shall maintain all metering Equipment. Distributor shall keep all test results, maintenance programs, and sealing records. The Equipment data and test records shall be furnished by the Distributor to the User upon request.

8.5.4 Traceability of Metering Standard

The Distributor 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.

8.6 METER READING AND METERING DATA

8.6.1 Meter Reading and Recording Responsibility

8.6.1.1 Meter reading and recording shall be done by the authorized representative of the Distributor and witnessed by the authorized representative of the User on the date stipulated in a separate agreement.

8.6.1.2 The Distributor shall provide the Grid Owner and the Market Operator all metering data necessary to support operations of the WESM.

8.6.2 Running Totals of Metered Energy

8.6.2.1 Running totals of the Energy and Demand shall be available for each measured quantity. Combined meters which measure both the Active Energy

and Power input to and output from the Distribution System shall have the running totals available for each measured quantity and each direction.

- 8.6.2.2 At input/output connections, the Reactive Energy and Power metering shall provide the running totals for each measured quantity. Combined meters which measure both the Reactive Energy and Power input to and output from the Distribution System shall have the running totals available for each measured quantity, each direction, and each quadrant or combination of quadrants.

8.6.3 Collection, Processing, and Access to Metering Data

- 8.6.3.1 The collection and processing of metering data for bundled energy services shall follow the billing and settlement procedure and schedule of the Distributor.
- 8.6.3.2 The Distributor shall download Distribution System Integrating Pulse Meter data for billing and settlement purposes as often as required to support unbundled service operations.
- 8.6.3.3 The User shall be provided full access to the metering data of its Connection Point.

8.6.4 Metering Data for Billing and Settlement of Unbundled Services

- 8.6.4.1 The Market Rules of the WESM set out the weekly billing and settlement procedure. The Distributor shall develop a consistent procedure for providing metering data for Users on its Distribution System receiving power from power Suppliers of the WESM. The specific timeline includes:
- (a) By 1000 hours every Monday or first working day of the week, Distributor shall collect the metering data of the individual customers receiving unbundled energy services for the previous week.
 - (b) By 1200 hours of the same day, the Distributor shall submit to the Market Operator the hourly metering data at each metering point on its Distribution System to the Market Operator.
- 8.6.4.2 The Market Operator shall prepare consolidated billing statements based on the metering data at the User's metering point provided by the Distributors and the metering data at the Grid Connection Points provided by the System Operator. The consolidated billing statements for an End-User receiving unbundled power service may include, but not limited to:
- (a) Bulk power supply tariff;
 - (b) Transmission use of system charge;
 - (c) Distribution use of system charge;
 - (d) Transmission and distribution loss;
 - (e) Transmission bottleneck charge;
 - (f) Ancillary service charges; and
 - (g) Customer service charge (billing, metering, customer information, and others).

8.6.4.3 The Distributor may opt to handle its own billing and settlement for the End-Users on its System receiving unbundled power services. In this case, the Distributor's billing and settlement schedule shall be consistent with the weekly schedule of the WESM.

8.6.5 Validation and Substitution of Metering Data

8.6.5.1 The Distributor shall be responsible for the validation and substitution of metering data on its System.

8.6.5.2 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.

8.6.5.3 If a check meter is not available or the metering data is missing, then a substitute value shall be prepared by the Distributor using the data validation and substitution method approved by the ERC.

8.6.6 Storage and Availability of Metering Data

8.6.6.1 The Distributor shall be responsible for storing the metering data for the unbundled energy services for five years. No alteration to the metering data stored in the database shall be permitted.

8.6.6.2 User meter data is considered to be confidential and cannot be released without the written consent of the User.

8.7 SETTLEMENT AUDIT PROCEDURES

8.7.1 Right to Request Settlement Audit

The User have the right to request an audit of the settlement process related to its account and the right to choose an independent third party qualified to perform the audit. The Distributor shall cooperate in the auditing process. The settlement audit shall be based on the applicable provisions of the Market Rules.

8.7.2 Allocation of Audit Cost

The requesting party is responsible for all outside auditor costs unless the Distributor agrees to pay some or all of those costs.

8.7.3 Audit Result

The audit result shall be issued to the Distributor and the Distributor shall issue a response to the audit report, including any adjustment in account billing/payments proposed.

8.7.4 Audit Appeal

If the User disagrees with the Distributor's response to the audit, that response can be appealed to an arbitrator selected by the WESM Management Committee.

8.8 SETTLEMENT DISPUTE RESOLUTION

8.8.1 Settlement Dispute Resolution Process—First Stage

If the Distributor's contract manager and the User's representative cannot resolve a settlement dispute, both parties shall document their positions and submit them to their direct supervisors. Those supervisors shall attempt to resolve the dispute.

8.8.2 Settlement Dispute Resolution Process—Second Stage

If no resolution in the dispute is reached at the supervisors' level, the Distributor's position shall prevail. If the User continues to disagree, the issue can, on the User's request be submitted to a settlements arbitrator selected by the Market Operator. The arbitrator shall meet with the parties and attempt to reach an agreement between the parties. If agreement is not reached the arbitrator shall issue a decision that shall be honored by both parties.

8.8.3 Settlement Dispute Appeal Process

In rare cases where one party or the other believes that significant error has been made in an arbitrator's decision, that party can appeal the decision to the ERC.

CHAPTER 9

DISTRIBUTION CODE TRANSITORY PROVISIONS

9.1 PURPOSE AND SCOPE

9.1.1 Purpose

- (a) To provide guidelines for the transition of the electric power industry from the existing structure to the new structure as specified in the Act;
- (b) To establish procedures for Distributors and Distribution Users to develop and gain approval of transitional compliance plans where immediate compliance with the Distribution Code is not possible; and
- (c) To establish procedures which in some cases may allow permanent exemption from Distribution Code requirements.

9.1.2 Scope of Application

This Chapter applies to all electric power industry participants including:

- (a) Distributors;
- (b) Embedded Generators;
- (c) Large Customers;
- (d) Grid Owner;
- (e) System Operator;
- (f) Market Operator; and
- (g) Any other entity with a System connected to a Distribution System.

9.2 MANDATES OF THE ACT

9.2.1 Objectives of the Electric Power Industry Reform

The Act establishes that the objectives of restructuring the Philippine electricity sector are:

- (a) To ensure and accelerate the total electrification of the country;
- (b) To ensure the quality, reliability, security, and affordability of the supply of electric power;
- (c) To ensure transparent and reasonable prices of electricity in a regime of free and fair competition and full public accountability to achieve greater operational and economic efficiency and enhance the competitiveness of Philippine products in the global market;
- (d) To enhance the inflow of private capital and broaden the ownership base of the power generation, transmission, and distribution sectors;
- (e) To ensure fair and non-discriminatory treatment of public and private sector entities in the process of restructuring the electric power industry;

- (f) To protect the public interest as it is affected by the rates and services of electric utilities and other providers of electric power;
- (g) To assure socially and environmentally compatible energy sources and infrastructure;
- (h) To promote the utilization of indigenous and new and renewable energy resources in power generation in order to reduce dependence on imported energy;
- (i) To provide for an orderly and transparent privatization of the assets and liabilities of the National Power Corporation (NPC);
- (j) To establish a strong and purely independent regulatory body and system to ensure consumer protection and enhance the competitive operation of the electricity market; and
- (k) To encourage the efficient use of energy and other modalities of demand side management.

9.2.2 Structure of the Electric Power Industry

The electric power industry is divided into four (4) sectors. These are:

- (a) Generation Sector;
- (b) Transmission Sector;
- (c) Distribution Sector; and
- (d) Supply Sector.

9.2.3 Generation Sector

- 9.2.3.1 The generation of electric power, a business affected with public interest, shall be competitive and open.
- 9.2.3.2 Any new Generation Company shall, before it operates, secure from the ERC a certificate of compliance pursuant to the standards set forth in the Act, as well as health, safety, and environmental clearances from the appropriate government agencies under existing laws.
- 9.2.3.3 Power generation shall not be considered a public utility operation. For this purpose, any person or entity engaged or which shall engage in power generation and Supply of Electricity shall not be required to secure a national franchise.
- 9.2.3.4 Upon implementation of retail competition and open access, the prices charged by a Generation Company for the Supply of Electricity shall not be subject to regulation by the ERC except as otherwise provided in the Act.

9.2.4 Transmission Sector

- 9.2.4.1 The Act created the National Transmission Corporation (TRANSCO), which assumed the electrical transmission function of the National Power Corporation (NPC). The TRANSCO shall have the authority and responsibility for the planning, construction, and centralized operation and

maintenance of its high voltage transmission facilities, including Grid interconnection and Ancillary Services.

9.2.4.2 Within six (6) months from the effectivity of the Act, the transmission and sub-transmission facilities of NPC and all other assets related to transmission operations, including the nationwide franchise of NPC for the operation of the Grid, shall be transferred to the TRANSCO. The TRANSCO shall be wholly owned by the Power Sector Assets and Liabilities Management (PSALM) Corporation.

9.2.4.3 The TRANSCO shall have the following functions and responsibilities:

- (a) Act as the System Operator of the nationwide electrical transmission and Sub-transmission System, to be transferred to it by NPC;
- (b) Provide open and non-discriminatory access to its Transmission System to all Grid Users;
- (c) Ensure and maintain the Reliability, adequacy, Security, Stability, and integrity of the nationwide electrical Grid in accordance with the performance standards for the operation and maintenance of the Grid, as set forth in the Grid Code;
- (d) Improve and expand its Transmission facilities, consistent with the Grid Code and the Transmission Development Plan (TDP), to adequately serve Generation Companies, Distribution Utilities, and Suppliers requiring transmission service and/or Ancillary Services through the Transmission System;
- (e) Subject to technical constraints, TRANSCO shall provide Central Dispatch of all generation facilities connected, directly or indirectly, to the Transmission System in accordance with the Generation Schedule submitted by the Market Operator, taking into account outstanding bilateral contracts; and
- (f) TRANSCO shall undertake the preparation of the TDP.

9.2.4.4 In the preparation of the TDP, TRANSCO shall consult the other participants of the electric power industry such as the Generation Companies, Distribution Utilities, and the electricity End-Users. The TDP shall be submitted to the DOE for integration with the Power Development Program and the Philippine Energy Plan, provided for in Republic Act No. 7638 otherwise known as "*The Department of Energy Act of 1992*".

9.2.4.5 Within six (6) months from the effectivity of the Act, the PSALM Corp. shall submit a plan for the endorsement by the Joint Congressional Power Commission and the approval of the President of the Philippines. The President of the Philippines thereafter shall direct PSALM Corp. to award in open competitive bidding, the transmission facilities, including Grid interconnections and Ancillary Services to a qualified party either through an outright sale or a concession contract.

9.2.4.6 The buyer/concessionaire shall be responsible for the improvement, expansion, operation, and/or maintenance of its transmission assets and the operation of any related business.

9.2.4.7 The awardee shall comply with the Grid Code and TDP as approved. The awardee shall be financially and technically capable, with proven domestic and/or international experience and expertise as a leading transmission System Operator. Such experience must be with a Transmission System of comparable capacity and coverage as the Philippines.

9.2.5 Distribution Sector

9.2.5.1 The Distribution of Electricity to End-Users shall be a regulated common carrier business requiring a national franchise. Distribution of electric power to all End-Users may be undertaken by private Distribution Utilities, Electric Cooperatives, local government units presently undertaking this function, and other duly authorized entities, subject to regulation by the ERC.

9.2.5.2 The Distributor shall have the obligation to provide distribution services and connections to its System for any End-User within its Franchise Area consistent with the Distribution Code. Any entity engaged therein shall provide open and non-discriminatory access to its Distribution System to all Users.

9.2.6 Supply Sector

9.2.6.1 The supply sector is a business affected with public interest. Except for Distribution Utilities and Electric Cooperatives with respect to their existing Franchise Areas, all Suppliers of electricity to the contestable market shall require a license from the ERC.

9.2.6.2 The ERC shall promulgate rules and regulations prescribing the qualifications of Suppliers, which shall include among other requirements, a demonstration of their technical capability, financial capability, and creditworthiness.

9.2.6.3 The ERC shall have authority to require Suppliers to furnish a bond or other evidence of the ability of a Supplier to withstand market disturbances or other events that may increase the cost of providing service.

9.2.7 Retail Competition and Open Access

9.2.7.1 Retail competition and open access on distribution wires shall be implemented not later than three (3) years upon the effectivity of the Act, subject to the following conditions:

- (a) Establishment of the Wholesale Electricity Spot Market;
- (b) Approval of unbundled transmission and distribution wheeling charges;
- (c) Initial implementation of the cross subsidy removal scheme;
- (d) Privatization of at least 70 percent of the total capacity of generating assets of NPC Luzon and Visayas; and

(e) Transfer of the management and control of at least 70 percent of the total Energy output of power plants under contract with NPC to the IPP Administrators.

9.2.7.2 Upon the initial implementation of open access, the ERC shall allow all electricity End-Users with an average monthly peak Demand of at least one (1) MW for the preceding twelve (12) months to be the contestable market.

9.2.7.3 Two (2) years thereafter, the threshold level for the contestable market shall be reduced to 750 kW. At this level, aggregators shall be allowed to supply electricity to End-Users whose aggregate Demand within a contiguous area is at least 750 kW.

9.2.7.4 Subsequently and every year thereafter, the ERC shall evaluate the performance of the market. On the basis of such evaluation, it shall gradually reduce threshold level until it reaches the household Demand level.

9.2.7.5 In the case of Electric Cooperatives, retail competition and open access shall be implemented not earlier than five (5) years upon the effectivity of the Act.

9.3 DISTRIBUTION ASSET BOUNDARIES

9.3.1 Distributors' Assets

The Distribution Code applies to all Distribution Systems and the associated connection assets at all voltage levels owned and operated by the Distributors.

9.3.2 Disposal of Sub-transmission Functions, Assets, and Liabilities

9.3.2.1 Within two (2) years from the effectivity of the Act or the start of open access, whichever comes earlier, the TRANSCO shall negotiate with and thereafter transfer the sub-transmission functions, assets, and associated liabilities to the qualified Distribution Utility or utilities connected to such sub-transmission facilities.

9.3.2.2 Where there are two or more connected Distribution Utilities, the consortium or juridical entity shall be formed by and composed of all of them and thereafter shall be granted a franchise to operate the sub-transmission asset by the ERC.

9.3.2.3 The take over by a Distribution Utility of any sub-transmission asset shall not cause a diminution of service and quality to the End-Users.

9.3.2.4 The Grid Code shall no longer be applicable to the sub-transmission facilities once they have been transferred to Distributors. The transferred sub-transmission facilities shall be subject to the Philippine Distribution Code.

9.4 DISTRIBUTION RELIABILITY

9.4.1 Submission of Normalized Reliability Data

Within six (6) months from the promulgation of the Philippine Distribution Code, every Distributor shall submit to the ERC its Distribution Reliability Performance targets, normalized reliability data and performance for the last five (5) years, using SAIFI, SAIDI, and MAIFI.

9.4.2 Initial Reliability Targets

The initial targets for the Reliability Indices shall be equal to the mean value of the particular Distributor's reliability performance for the last five years. The upper and lower cutoff points shall be set at plus or minus one (± 1) standard deviation from the mean value.

9.5 MARKET TRANSITION

9.5.1 Establishment of the Wholesale Electricity Spot Market

Within one (1) year from the effectivity of the Act, the DOE shall establish a Wholesale Electricity Spot Market composed of the wholesale electricity spot market participants. The market shall provide the mechanism for identifying and setting the price of actual variations from the quantities transacted under contracts between sellers and purchasers of electricity.

9.5.2 Membership to the WESM

9.5.2.1 Subject to the compliance with the membership criteria, all Generating Companies, Distribution Utilities, Suppliers, Large Customers/End-Users, and other similar entities authorized by the ERC shall be eligible to become members of the WESM.

9.5.2.2 The ERC may authorize other similar entities to become eligible as members, either directly or indirectly, of the WESM.

9.5.3 Market Rules

9.5.3.1 Jointly with the Electric Power Industry Participants, the DOE shall formulate the detailed rules for the WESM. Said rules shall provide the mechanism for determining the price of electricity not covered by bilateral contracts between sellers and purchasers of electricity.

9.5.3.2 The price determination methodology contained in the Market Rules shall be subject to the approval of ERC.

9.5.3.3 The Market Rules shall also reflect accepted economic principles and provide a level playing field to all Electric Power Industry Participants. The rules shall provide, among others, producers for:

- (a) Establishing the merit order dispatch instructions for each time period;
- (b) Determining the market-clearing price for each time period;

- (c) Administering the market, including criteria for admission to and termination from the market which includes security or performance bond requirements, voting rights of the participants, surveillance and assurance of compliance of the participants with the rules, and the formation of the WESM governing body;
- (d) Prescribing guidelines for the market operation in system emergencies; and
- (e) Amending the Market Rules.

9.5.3.4 All Generation Companies, Distribution Utilities, Suppliers, Large Customers/End-Users, and other similar entities authorized by the ERC, whether direct or indirect members of the WESM shall be bound by the Market Rules with respect to transactions in the Spot Market.

9.5.4 The Market Operator

9.5.4.1 The Wholesale Electricity Spot Market shall be implemented by a Market Operator in accordance with the Market Rules. The Market Operator shall be an autonomous group, to be constituted by DOE, with equitable representation from Electric Power Industry Participants, initially under the administrative supervision of the TRANSCO.

9.5.4.2 The Market Operator shall undertake the preparatory work and initial operation of the WESM. Not later than one (1) year after the implementation of the WESM, an independent entity shall be formed and the functions, assets and liabilities of the Market Operator shall be transferred to such entity with the joint endorsement of the DOE and the Electric Power Industry Participants. Thereafter, the administrative supervision of the TRANSCO over such entity shall cease.

9.5.5 Guarantee for the Electricity Purchased by Small Utilities

The NEA may, in exchange for adequate security and a guarantee fee, act as a guarantor for purchases of electricity in the WESM by any Electric Cooperative or small Distribution Utility to support their credit standing.

9.6 EXISTING CONTRACTS

9.6.1 Effectivity of Existing Contracts

The Distribution Code shall apply to existing Contracts insofar as it does not impair the obligations arising therefrom.

9.6.2 New or Amended Contracts

Distributors shall negotiate (according to schedules established in their Transitional Compliance Plans) for new or amended contracts that shall conform to the provisions of the Distribution Code in order to attain a uniform implementation of Distribution Code standards.

9.7 TRANSITIONAL COMPLIANCE PLANS

9.7.1 Statement of Compliance

Within six (6) months from the effectivity of the Distribution Code, Distributors shall submit to the ERC a statement of their compliance with the technical specifications, performance standards, and financial capability standards prescribed in the Distribution Code.

9.7.2 Submission of Compliance Plans

Distributors which do not comply with any of the prescribed technical specifications, performance standards, and financial capability standards shall submit to the ERC a plan to comply, within three (3) years, with said prescribed technical specifications, performance standards, and financial standards.

9.7.3 Failure to Submit Plan

Failure to submit a feasible and credible plan and/or failure to implement the same shall serve as grounds for the imposition of appropriate sanctions, fines, or penalties.

9.7.4 Evaluation and Approval of Plans

9.7.4.1 The ERC shall, within 60 days from receipt of such plan, evaluate the same and notify the Distributor of its action.

9.7.4.2 The ERC shall review the submitted transitional compliance plans and either approve the plans or return them with required revisions.

9.8 CONNECTION REQUIREMENTS FOR NEW AND RENEWABLE ENERGY SOURCES

The connection requirements for Embedded Generating Plants that utilize non-conventional Equipment for new and renewable energy sources that may have an impact in the Distribution System, shall be prescribed by the ERC after due notice and hearing.

9.9 EXEMPTIONS FOR SPECIFIC EXISTING EQUIPMENT

9.9.1 Requests for Permanent Exemption

Requests for permanent exemptions of Equipment to Distribution Code provisions shall be submitted to the Distributor on a case-by-case basis.

9.9.2 Approval of Exemption

The Distributor shall approve requests for exemption only for cases where the Reliability of the Distribution System will not be compromised and upgrading the Equipment cannot be economically justified.