OFFICE OF UTILITIES REGULATION

Regulating Utilities for the Benefit of All

JAMAICA ELECTRICITY SECTOR

BOOK OF CODES

2016 August

GENERATION CODE – TRANSMISSION CODE – DISTRIBUTION CODE – DESPATCH CODE – SUPPLY CODE

Office of Utilities Regulation

3rd Floor PCJ Resource Centre

36 Trafalgar Road

Kingston 10

Jamaica W.I.

Tel: (876) 968-6053 Fax: (876) 929-3635

http://www.our.org.jm

Toll Free from land lines: 1-888-CALL-OUR (2255-687)

2016 August

DOCUMENT TITLE AND APPROVAL PAGE

DOCUMENT NUMBER: 2016/ELE/005/TEC.001

DOCUMENT TITLE: Jamaica Electricity Sector Book of Codes

PURPOSE OF DOCUMENT:

This regulation covers the guiding principles, operating procedures, and Technical Standards governing operation of the Jamaican Electric Power Grid and all interconnected Generating Facilities. The regulation adopts five Grid Codes which have been developed in parallel, designed to provide a comprehensive framework for the development, maintenance and operation of an efficient, safe, and reliable Jamaican Power Grid.

ANTECEDENT DOCUMENTS:

Document Number	***Description***	***Date***
2013/003/ELE/TEC/001	Electric Utility Sector Generation Codes	2013 July 29

REVISIONS:

Section/Code	***Version***	***Date***

APPROVAL:

This document is approved by the Office of Utilities Regulation and the provisions therein become effective **2016 August 29.**

On behalf of the Office:

Joseph M. Matalon
Chairman

2016 August 29

Table of Contents

Introduction Code

IC

IC 1 INTRODUCTION TO CODES

This Introduction and each of the Codes comprise the substance of the Book of Codes. The Codes are organized into a single Book of Codes for the convenience of the System Users and it allows a more convenient reference to related provisions in the other Codes. The Introduction provides background information which places the Codes in context; an overview of the legal authority for the Codes; sets out the purpose and organization of the Book of Codes; the procedure for revision of and compliance with the Codes; guidance on interpretation of the Codes; and defines the Terms and Definitions applicable to the Codes.

IC 1.1 Purpose of the Codes

These Codes cover the guiding principles, operating procedures, and Technical Standards governing operation of the System and all interconnected Generating Facilities.

The Codes have been developed in parallel, designed to provide a comprehensive framework for the development, maintenance and operation of an efficient, safe, and reliable System. Each of the five Codes, that is, the Generation, Transmission, Distribution, Supply, and Despatch Codes, is designed to be used in conjunction with the other four Codes. The Codes cover all material, technical aspects relating to Interconnection to, Operation, and use of the System (and insofar as they affect the System, the Operation of User electric lines and electrical Plants connected to that System). The Codes prohibit any undue discrimination among Users and categories of Users of the Grid. The Codes also provide technical guidance to all Users in relation to the optimal approach to planning, operation and use of the power Grid. The Codes have been designed to be consistent with internationally required technical standards and with Prudent Utility Practice, and to address the specific needs of the Grid and its Users.

The Codes are authorized by and enforceable under the provisions of the Electricity Act, the Office of Utilities Regulation Act as well as the Electricity Licence. The Codes will supersede all existing codes pertaining to the electricity sector.

The Codes have been developed in extensive consultation with the Users of the Grid, and with the Ministry responsible for energy. The Codes repeal the existing Generation Code and replaces it with a Book of Codes with detailed provisions.

In the event of any inconsistency with any provision of the Codes with the Electricity Act or any regulations made thereunder, the Electricity Act and the regulations will be applicable to the extent of the inconsistency.

IC 2 LEGAL AUTHORITY FOR PROMULGATION OF CODES

IC 2.1 Electricity Act

Section 47 of the Electricity Act requires that OUR, with the approval of the Minister, prepare and promulgate the Codes listed therein within twelve months after August 27, 2015. The Codes are defined in section 2 of the Electricity Act as the Generation Code, Transmission Code, Distribution Code, Supply Code and Despatch Code. The Codes are to provide general direction to electricity sector licensees and the Despatch Code, in particular, must contain a process for OUR investigation of any significant power outage. Section 47 of the Electricity Act further provides that a breach of the Codes by a licensee constitutes a breach of the electricity licence held by the licensee (this is not applicable to a licensee that existed prior to August 27, 2015, the appointed day of the Electricity Act). Also, any breach of the Codes by a licensee or a Self-Generator who is not a licensee, shall constitute an offence under the Electricity Act. The OUR through the consultative process with electricity sector stakeholders must review the Codes at least every three years and publish same.

In discharging this responsibility, generally the OUR takes guidance from the objectives set forth in section 3 of the Electricity Act, and specifically the following objectives: (1) the provision of a modern system of regulation of the generation, transmission, distribution, supply, Despatch and use of electricity; (2) the promotion of clarity in relation to the respective roles and responsibilities of the stakeholders in the electricity sector; (3) facilitation of an efficient, effective, sustainable and orderly development and operation of the electricity supply infrastructure, supported by adequate levels of investment; (4) promotion of energy efficiency and the use of renewable and other energy sources; (5) prescription of the required standards in the electricity sector; (6) protection and safety of consumers of electricity and the public; and (7) ensuring that the regulation of the electricity sector is transparent and predictable.

IC 2.2 Office of Utilities Regulation Act

Section 4(1) (a) of the OUR Act charges OUR with the function of regulating the provision of prescribed utility services by licensees or specified organizations. In the absence of provisions in the Electricity Act and the Electricity Licence, the OUR Act prescribes the manner in which the OUR must operate in carrying out its functions and the exercise of its powers. Section 4(3) of the OUR Act provides that in undertaking its functions, OUR shall undertake such measures as it considers necessary or desirable to:

a. encourage competition in provision of prescribed utility services;

b. protect the interests of consumers in relation to the supply of a prescribed utility service;

c. encourage the development and use of indigenous resources;

d. promote and encourage the development of modern and efficient utility services; and

e. enquire into the nature and extent of the prescribed utility services provided by licensees or specified organizations.

IC 3 PREVIOUS CODES

The OUR, in th past, has promulgated codes, which provided guidance to licensees on the rules and procedures designed to assure a secure and reliable supply of electricity with the most recent being the Electric Utility Sector Generation Code, July 2013 (Document No. 2013/003/ELE/TEC/001).

In addition, Licensee, working with a Code Review Panel of stakeholders, produced a proposed draft of a Transmission Grid Code and a Distribution Grid Code in 2011, pursuant to the All-Island Electric Licence, 2001. These draft codes, combined with then existing Generation Code, provided the foundation for the development of these Codes. Appropriate revisions were made to the draft codes to reflect the requirements of Electricity Act to promulgate the Codes, and the input from electricity sector stakeholders was sought and provided during extensive consultations.

The Codes repeal the existing Electric Utility Sector Generation Code and the content of the Codes draws upon all prior development work of the draft codes to promulgate this integrated and comprehensive Book of Codes.

IC 4 OVERVIEW OF THE CODES

The Introduction contains the Terms and Definitions applicable to all five (5) Codes, which is set out in Appendix A. The table of Technical Standards is included in Appendix B. This Technical Standards list includes all technical and engineering standards or guidelines specifically referenced in the Codes. Any reference to these standards or guidelines shall be interpreted to reference the then-current version of the standard, bulletin, or guideline as published by the promulgating organization.

The Generation Code covers the Generator Interconnections to the Transmission or Distribution Systems. The responsibility boundary between the Generator and the System Operator will normally be the High Voltage side of the Generating Unit transformer. The Transmission Code covers the Transmission System including electric power lines operating at 69 kV and above (including

138kV and 69kV systems) and including the secondary circuit breakers and up to the outgoing Isolators at Transmission Substations transforming to 24kV, 13.8kV and 12kV. The Distribution Code covers the Distribution System from the point of the outgoing Isolators on the Transmission Substations as described above, to the point of Interconnection with the Customers system. The Supply Code covers the sale of electricity to customers by the Supply Licensee. The Despatch Code controls the Despatch Licensee in their activities involved in the central management and direction of Generating Plants and other sources of supply to the Grid. The diagram set forth in Figure 1 below illustrates the various boundaries.

In the Codes, the Licensee has responsibilities in two distinct capacities, they are as follows:

a. Licensee is responsible for prudent and efficient management of the System by virtue of its holding of the Licence. The Codes apply the term "System Operator" whenever referring to the Licensee in this capacity; and

b. As the owner of power stations, Licensee is also subject to the rights and obligations in this regulation as it applies to Generators, and any reference to "Generators" in this regulation should be interpreted to include Licensee in this capacity.

Given Jamaica's high dependence on petroleum-based fuels for electrical energy requirements and its susceptibility to fuel price volatility, it is important that the country achieves its energy diversifications objectives in the medium to long term, taking into account, economic cost, efficiency, environmental considerations and appropriate technologies. The Codes therefore introduce detailed provisions to assure the smooth integration of the renewable energy and energy efficiency initiatives envisioned by the National Energy Policy 2009-2030. The provisions are designed to enable achievement of the Policy goal of 20% of net energy to the System being provided by renewable energy by 2030, and any revisions of the target as prescribed by the Minister, while maintaining a safe, secure, stable and reliable Grid. These renewable energy and energy efficiency integration provisions address minimum technical conditions for the integration to the System of renewable energy generation sources in line with international best practices and standards, planning and operational responsibilities and requirements related to feasibility studies and system studies. These requirements will evolve with time, to respond to technological advances and to support increasingly higher levels of renewable energy penetration and innovative use of energy efficiency initiatives.

IC 5 GENERATION CODE

The Generation Code governs Generation activities in the electricity sector and interconnected to the Grid. The Generation Code covers the guiding principles, operating procedures and Technical Standards governing all Generating Plants interconnected to the Grid. The Generation Code seeks to facilitate the economic, safe and reliable operation of the Grid. The Generation Code facilitates the System being made available to persons authorized to generate electricity and to interconnect with the System, and is conceived as a statement of what is optimal (particularly from a technical point of view) for all Users and the System Operator itself in relation to the planning, operation and use of the System. It seeks to avoid any undue discrimination between Users and categories of Users.

The Generation Code is divided into the following sections:

SECTION 1	**SCOPE**
SECTION 2	**INTERCONNECTION CONDITIONS** Specifies the normal method of Interconnection and the minimum technical, design and operational criteria which must be complied with by all Generators and prospective Generators.
SECTION 3	**OPERATIONAL METERING** Specifies the Technical Standards and procedures for metering applicable to Metering Systems installed by Generators.
SECTION 4	**MERIT ORDER SYSTEM** Specifies the requirement of the System Operator to establish a Merit Order system based on the real or contracted Variable Operating Cost component of each Generating Unit or Complex.
SECTION 5	**SCADA INTERFACING** This section sets out the technical requirements for connections to the System Operator's Supervisory Control and Data Acquisition (SCADA) system outstation in terms of electrical characteristics.
SECTION 6	**COMMUNICATION AND REPORTING**

	Sets out the requirement of a Generator to provide information as requested, pertaining to the operation of their Generating Unit(s).
SECTION 7	**FUEL SUPPLY AGREEMENT** Specifies the minimum requirements of the Generator Fuel Supply Agreement.
SECTION 8	**GENERATOR SCHEDULING AND DISPATCHING TOOLS** Specifies the procedures for Generating Unit scheduling, dispatch, System security and communications between Generators and the System Operator via the System Control Centre.
SECTION 9	**NEW TECHNOLOGIES** Makes provision for new technologies that have parameters not covered by the Code which may be given consideration for inclusion to the System.
SECTION 10	**GENERATOR MAINTENANCE PLANNING** Specifies the criteria and procedures governing the planning and scheduling of maintenance requirements of Generators' Generating Facilities.
SECTION 11	**SCHEDULES OF RESPONSIBILITIES** Specifies the ownership and the responsibilities for Operation and Maintenance which shall be jointly agreed by the System Operator and the appropriate Generator for each location.
SECTION 12	**TESTING AND MONITORING** Specifies the list, timetable and procedures for all tests to be performed by the Generator and System Operator.
SECTION 13	**MONITORING AND CONTROL** Specifies the method of monitoring and controlling of the system by the System Operator, and the method by which the System Operator and Users can communicate with each other as well as exchanging data signals for the monitoring and control of the system.
SECTION 14	**UNFORESEEN CIRCUMSTANCES**

	Makes provisions for circumstances which may arise and which are not addressed by the Code.
SECTION 15	**GENERATION INTERCONNECTION STUDIES** Specifies the type of studies required to be carried out by Users and potential Users of the system who require to interconnect a Generator to the System.

IC 6 TRANSMISSION CODE

The Transmission Code applies to the conveyance of electricity by means of the Transmission System, which includes electric power lines operating at 69kV and higher, including the secondary circuit breakers and up to the outgoing Isolators at Transmission Substations transforming to 24kV, 13.8kV and 12kV. The Transmission Code provides the guidelines controlling the development, maintenance and operation of an efficient, coordinated and economic Transmission System in Jamaica. The Transmission System being made available to persons authorized to supply or generate electricity and is conceived as a statement of what is optimal (particularly from a technical point of view) for all Users and the System Operator itself in relation to the planning, operation and use of the Transmission System. It seeks to avoid any undue discrimination between Users and categories of Users.

The procedures and principles governing the System Operator's relationship with all Users of the Transmission System are set out in the Transmission Code. The Transmission Code specifies day-to-day procedures for both planning and operational purposes and covers both normal and exceptional circumstances.

The Transmission Code will cover the System from the point of the outgoing isolators on the Transmission Substations as described above, to the point of Interconnection with the Customer's system.

The Transmission Code covers the Generator Interconnections to the Transmission or Distribution Systems. The responsibility boundary between the Generator and the System Operator will normally be the High Voltage side of the Generating Unit transformer. The Transmission Code is divided into the following sections:-

SECTION 1	**SCOPE**
SECTION 2	**GENERAL REQUIREMENTS**

	This is intended to ensure, so far as possible, that the various sections of the Transmission Code work together and work in practice
SECTION 3	**TRANSMISSION PLANNING** Sets out responsibility of the Minister for planning the development of the System, the planning process for transmission and distribution and the necessary consideration of the location of renewable and other generation sources, taking into account the potential for electrification of rural areas.
SECTION 4	**MAINTENANCE STANDARDS** Specifies the maintenance standards that all Plant and Apparatus on the System shall be operated and maintained in accordance with Prudent Utility Practice and in a manner that shall not pose a threat to the safety of employees or the public.
SECTION 5	**TRANSMISSION INTERCONNECTION** Specifies the normal method of Interconnection to the Transmission System and the minimum technical, design and operational criteria which must be complied with by any User or prospective User.
SECTION 6	**POWER QUALITY STANDARDS** Specifies the quality standards of the voltage, including its frequency and the resulting current, that are measured in the Transmission System during normal conditions and contingency conditions.
SECTION 7	**PLANT AND APPARATUS RELATING TO INTERCONNECTION SITES** Specifies the conditions that all Plant and Apparatus relating to the User/System Operator at the Interconnection Point, shall be compliant with.
SECTION 8	**SITE RELATED CONDITIONS** Specifies the responsibility for site safety, responsibility schedules, and operations related matters at an Owner's site.
SECTION 9	**OPERATIONAL COMMUNICATIONS**

	Sets out the requirements for the exchange of information in relation to Operations on the Transmission System which have, or may have, an Operational Effect.
SECTION 10	**DEMAND CONTROL** Specifies the provisions made by the System Operator and procedures to be followed by the System Operator and Users to permit a reduction in Demand in the event that there is insufficient Generation available to meet Demand in all or any part of the Transmission System.
SECTION 11	**SYSTEM CONTROL** Sets out the System Control responsibilities, control documentation, system diagram and communications.
SECTION 12	**CONTINGENCY PLANNING** Specifies the requirement of the System Operator to develop a strategy to be implemented in Emergency Conditions of a Major System Failure.
SECTION 13	**INCIDENT INFORMATION SUPPLY** Specifies the requirement of the System Operator and Generators to issue notices of all Incidents on their respective Systems that have or may have implications for the Transmission System or a User's System.
SECTION 14	**COMMUNICATIONS AND CONTROL** Specifies the telecommunications requirements between Users and the System Operator which must be established if required by the System Operator.
SECTION 15	**NUMBERING AND NOMENCLATURE** Sets out the requirement for numbering and nomenclature that must be used for Transmission Apparatus on Users' Sites and User Apparatus on Transmission Sites.
SECTION 16	**TESTING, MONITORING AND INVESTIGATION** Sets out the authorization required and the procedures to be followed by the System Operator, and Users wishing to conduct

	Operational Tests or Site Investigations involving Plant and Apparatus connected to, or part of, the Transmission System.
SECTION 17	**TRANSMISSION METERING** Sets out the way in which power and energy flows shall be measured at an Operational Interface.
SECTION 18	**TRANSMISSION SYSTEM DATA REGISTRATION** Provides details of the Schedules covering the data to be exchanged between the System Operator and the Users of the Transmission System.

IC 7 DISTRIBUTION CODE

The Distribution Code governs the distribution system and activities related thereto. It is designed to (a) permit the development, maintenance and operation of an efficient, coordinated and economic Distribution System in Jamaica; and (b) facilitate the Distribution System being made available to persons authorized to supply or generate electricity. The Distribution Code is conceived as a statement of what is optimal (particularly from a technical point of view) for all Users and the System Operator itself in relation to the planning, operation and use of the Distribution System. It seeks to avoid any undue discrimination between Users and categories of Users.

The procedures and principles governing the System Operator's relationship with all Users of the Distribution System are set out in the Distribution Code. The Distribution Code specifies day-to-day procedures for both planning and operational purposes and covers both normal and exceptional circumstances.

The Distribution Code will cover the Distribution System from the point of the outgoing isolators on the Transmission Substations as described above, to the point of Interconnection with the Customers system.

The Distribution Code is divided into the following sections:

SECTION 1	**SCOPE**
SECTION 2	**GENERAL REQUIREMENTS** General Requirements which are intended to ensure, so far as possible, that the various sections of the Distribution Code work together with the other four Codes.
SECTION 3	**DISTRIBUTION PLANNING** Sets out the responsibility of Minister for planning the development of the System which planning includes further requirements that the planning process for Distribution System considers the location of renewable and other generation sources, taking into account the potential for electrification of rural areas.
SECTION 4	**EMBEDDED GENERATION**

	Specifies the data requirements required from Embedded Generators to assess the impact that the Embedded Generator will have on the Distribution System.
SECTION 5	**DISTRIBUTION INTERCONNECTION** Specifies the normal method of interconnection to the Distribution System and the minimum technical, design and operational criteria which must be complied with by any User or prospective User.
SECTION 6	**POWER QUALITY STANDARDS** Specifies the quality of the voltage, including its frequency and the resulting current that is measured in the Distribution System during normal conditions and contingency conditions.
SECTION 7	**PLANT AND APPARATUS RELATING TO INTERCONNECTION SITES** Specifies the requirements for all Plant and Apparatus relating to the Users/System Operator at the Interconnection Point to be compliant with the provisions of the Code.
SECTION 8	**SITE RELATED CONDITIONS** Specifies the responsibilities of the Parties and requirements for safety, responsibility schedules, and operational requirements.
SECTION 9	**COMMUNICATIONS AND CONTROL** Sets out the telecommunication requirements between User(s) and the System Operator which must be established if required by the System Operator to ensure control of the Distribution System.
SECTION 10	**TESTING AND MONITORING** Specifies the requirement to test and/or monitor the Distribution System to ensure that Users are not operating outside the technical parameters required by this Code.
SECTION 11	**DEMAND CONTROL** Specifies the provisions to be made by the System Operator or a User with Systems connected to the Distribution System, in certain circumstances, to permit reductions in total Demand in

	the event of insufficient Generating Plants being available to meet total Demand.
SECTION 12	**OPERATIONAL COMMUNICATION** Sets out the requirements for the exchange of information in relation to Operations and/or Incidents on the Distribution System or any User System connected to the Distribution System which have had, or may have, an Operational Effect on the Distribution System or any other User System.
SECTION 13	**MAINTENANCE STANDARDS** Sets out the requirements for maintenance of all Plant and Apparatus on the System including maintenance standards, maintenance policy and maintenance records.
SECTION 14	**COMPETENCY OF STAFF** Sets out the requirement for the System Operator to have in place training polices that serve to ensure that persons operating, maintaining, testing and controlling the System Operator Transmission and Distribution Systems are competent for the tasks to be undertaken.
SECTION 15	**SWITCHING INSTRUCTIONS** Specifies the requirement for switching on the Distribution System.
SECTION 16	**NUMBERING AND NOMENCLATURE** Sets out the responsibilities and procedures for notifying the relevant owners of the numbering and nomenclature of Apparatus at Interconnection Points.
SECTION 17	**SPECIAL SYSTEM TESTS** Sets out the responsibilities and procedures for arranging and carrying out Special System Tests which have or may have an effect on the System Operator’s Distribution System or Users Systems.
SECTION 18	**DISTRIBUTION METERING**

	Specifies the requirements for metering the Active and Reactive Energy and Demand input to and/or output from the Distribution System.
SECTION 19	**DISTRIBUTION DATA REGISTRATION** Sets out a unified listing of all data required by the System Operator from Users and by Users from the System Operator. The diagram set forth in Figure 1 describes the boundaries among the various Code jurisdictions.

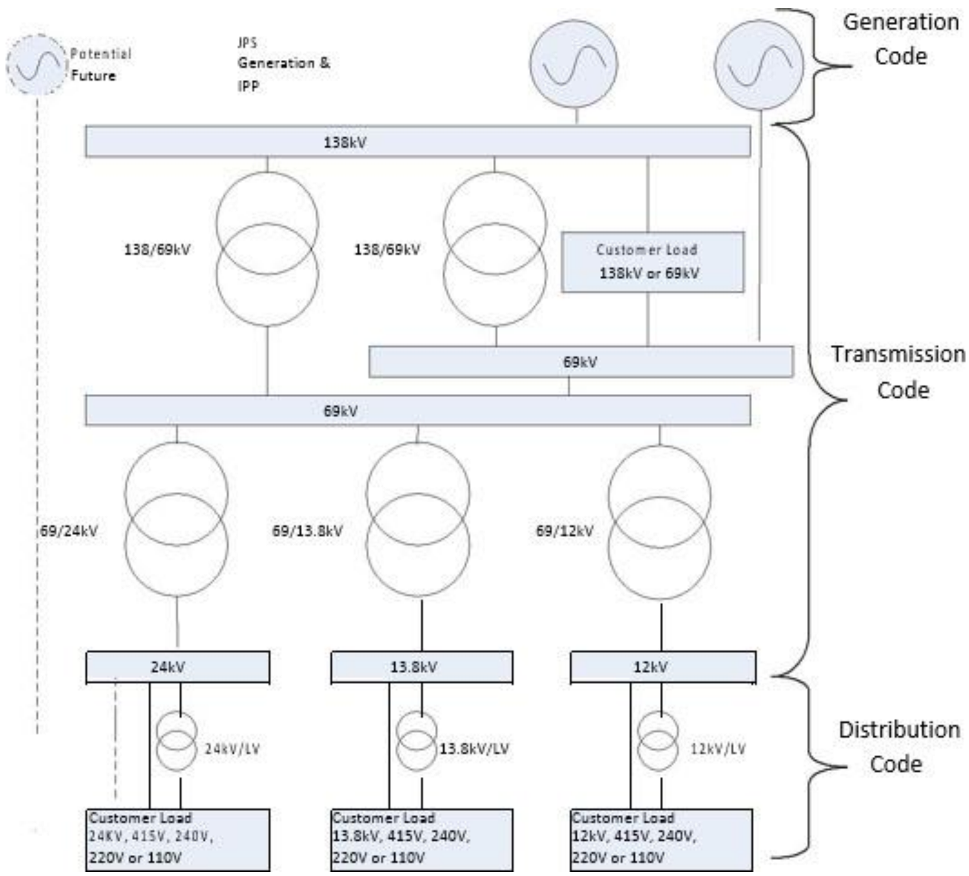


Figure 1 - Boundaries between the Transmission, Distribution and Generation Codes

IC 8 DESPATCH CODE

The Depatch Code governs the Despatch activities of the System Operator. The Despatch Code is designed to (a) permit the development, maintenance and operation of an efficient, coordinated and economic Grid; and (b) facilitate the Transmission and Distribution Systems being made available to persons authorized to supply or generate electricity. The Despatch Code is conceived as a statement of what is optimal (particularly from a technical point of view) for all Users and the System Operator itself in relation to the planning, operation and use of the System. It seeks to avoid any undue discrimination between Users and categories of Users.

The purpose of the Despatch Code is to:

a. set out the roles, responsibilities and process for the scheduling and Despatch of Generation and demand-side resources in meeting the electricity demand;

b. enable the System Operator to coordinate maintenance outages as far as possible in advance to allow the System Operator to maintain system integrity and reliability;

c. set out the process of investigation followed by the OUR in response to significant power outages; and

d. ensure fair and equitable treatment of all Generators connected to the Grid.

The Despatch Code is divided into the following sections:

SECTION 1	**INTRODUCTION TO THE CODE**
SECTION 2	**CONFIDENTIALITY**
SECTION 3	**SHORT TERM OPERATIONAL PLANNING** Sets out the requirements for system data, procedure and timing for the System Operator to carry out operational planning.
SECTION 4	**OPERATING MARGIN** Sets out the types of reserves making up the Operating Margin that the System Operator may use in the Control Phase.

SECTION 5	**MERIT ORDER SYSTEM** Specifies the requirements for the System Operator to establish a Merit Order based on the real or contracted Variable Operating Cost component of each Generating Unit or Complex.
SECTION 6	**UNIT SCHEDULING and COMMITTMENT** Specifies the System Operator's obligation to prepare a Unit Commitment and Dispatch Schedule which reasonably reflects the likely System conditions.
SECTION 7	**SCADA SYSTEM UPDATE** Specifies the requirement for the System Operator to update the daily projected Demand Forecast in real time.
SECTION 8	**INSTRUCTION TO SYNCHRONIZE / DESYNCHRONIZE** Specifies the times at which a Generator shall be synchronized and desynchronized which shall be directed by the System Control Engineer.
SECTION 9	**FREQUENCY AND VOLTAGE CONTROL** Specifies the adherence to the frequency and voltage standards to be the responsibility of the System Control Engineer.
SECTION 10	**OPERATING RESERVE MONITORING AND MANAGEMENT** Specifies the System minimum Spinning Reserve margin, operating reserves.
SECTION 11	**DISPATCH DEVIATION TRACKING AND REPORTING** Specifies the recording of all dispatch instructions and the compliance of each Generator with the instructions received.
SECTION 12	**SAFETY CO-ORDINATION** Sets out the requirement to ensure that the safety procedures adopted on either side of a Interconnection Point work together to ensure the safety of personnel, and/or Plant.
SECTION 13	**CONTINGENCY PLANNING**

	This sets out the details of the System recovery procedures following a Major System Failure.
SECTION 14	**INCIDENT INFORMATION SUPPLY** Sets out the requirements of the System Operator and Generators to issue notices of all Incidents on their respective Systems that have or may have implications for the Transmission System or a User's System.
SECTION 15	**METERING AND DATA ACQUISITION** Refers to the contents of the System Operator's SCADA policy.
SECTION 16	**DATA TO BE EXCHANGED BETWEEN THE SYSTEM OPERATOR AND GENERATORS** Provides details of Schedules covering the data to be exchanged between the System Operator and Generators.
SECTION 17	**DATA SCHEDULES** **Provides details of the Schedules covering the data to be exchanged between the System Operator and the Users of the System.**

IC 9 SUPPLY CODE

The Supply Code specifies the rules governing the obligations of the Licensee and consumers vis-à-vis each other.

The purpose of the Supply Code is to specify the set of practices that shall be adopted by the Licensee to provide efficient, cost effective and consumer friendly service to the Customers.

This Supply Code shall be applicable to:

a. the Licensee and all consumers in the Island of Jamaica as covered under the Act; and

b. unauthorized supply, unauthorized use, diversion and other means of unauthorized use/ abstraction/theft of electricity.

The Supply Code consists of the following sections:

SECTION 1	**INTRODUCTION TO THE CODE**
SECTION 2	**SYSTEM OF SUPPLY AND CLASSIFICATION OF CUSTOMERS** **Describes the system of supply classification of Customers, tariff and applicable conditions of supply.**
SECTION 3	**NEW CONNECTIONS** **Sets out the Licensee's Obligations to provide a supply of electricity and the requirements to be met by the Applicant for supply.**
SECTION 4	**CUSTOMERS WITH EMBEDDED GENERATION** **Sets out the connection requirements for customers with Embedded Generation.**
SECTION 5	**POINT OF SUPPLY DELIVERY, LICENSEE'S EQUIPMENT IN PREMISES** **Defines the Point of Supply Delivery to the Customers.**

SECTION 6	**WIRING AND APPARATUS ON CUSTOMER'S PREMISES** Sets out the general wiring conditions and the requirements for electrical installations and Apparatus in Customer's Premises
SECTION 7	**CONTRACT DEMAND AND AGREEMENT (TARIFF DESIGN)** Sets out the Contract Demand, Procedures for enhancement a reduction and rephrasing of Contract Demand,
SECTION 8	**METERING AND BILLING** Sets out the requirement of meters, supply and installation of meters, and testing of meters.
SECTION 9	**CUSTOMER PROVIDING DEMAND RESPONSE (RESERVED)**
SECTION 10	**PAYMENT AND DISCONNECTION** Sets out payment, disconnection and reconnection conditions
SECTION 11	**BACK BILLING AND IRREGULARITIES** Sets out the conditions and circumstances under which back billing of Customers may take place
APPENDIX	

IC 10 CODE TERMINOLOGY

IC 10.1 Glossary, Definition and Acronyms

The Codes terminology and capitalized terms are set forth in Appendix A, Table of Definitions and Acronyms.

IC 11 MODIFICATIONS TO THE CODES

IC 11.1 Code Review Panel

The Office shall review the Codes every three years, and in conducting that review shall consult the stakeholders in the electricity sector.

Modification of the Codes shall be executed by the OUR through a Code Review Panel established by the OUR in accordance with sub-section 11.2.

The Office shall establish and maintain a Code Review Panel, which will be a standing body charged with reviewing the Codes. The Review Panel shall report to the OUR on its dealings and, as appropriate, recommend amendments to the Codes for the OUR's consideration. The accepted recommendation shall be submitted to the Minister with responsibility for energy approval before promulgation.

IC 11.2 Duties of the Code Review Panel.

The functions of the Review Panel shall be as follows:

a. to ensure that all operational procedures and requirements governed by the Codes remain up to date;

b. to ensure that the Codes are consistent in their approach and are developed in a consistent manner;

c. consider recommendations made by subcommittees established to focus on specialized issues;

d. review all proposals for amendments to the Codes which the System Operator, the Generators, other Users, or the OUR, from time to time may wish to submit to the Review Panel for consideration;

e. consider unforeseen circumstances referred to it by the System Operator and determine whether the actions taken by the System Operator were justified and what changes, if any, are necessary to the Codes;

f. consider whether decisions of the OUR require revision of the Codes;

g. present recommendations to the OUR as to amendments to the Codes that it considers necessary and the reason for such changes; and

h. present its dealing and recommendations to the OUR as to amendments to the Codes that it considers necessary and the reason for such changes for the OUR's approval.

IC 11.3 Composition of the Code Review Panel

The Review Panel shall consist of the following persons drawn from the following categories and appointed by the OUR:

a. A representative of the OUR;

b. A representative of the System Operator's System Control Centre;

c. A representative of the System Operator employed to work with the Transmission System;

d. A representative of the System Operator employed to work with the Distribution System;

e. A representative of the Licensee employed to work with its Generators;

f. One representative of the IPPs

g. One representative of the operators of Co-Generators; and

h. A representative of the Net Billing, Power Wheeling or Auxiliary Interconnection Users.

The Office shall appoint the chairperson of the Review Panel.

IC 11.4 Operations of the Review Panel

The Review Panel shall establish rules for the conduct of its business, including terms of appointments and retirement of members, and submit same for the approval of the OUR.

The Review Panel shall meet at least twice per calendar year.

The Review Panel shall take its decisions by means of consensus. If the Review Panel is unable to reach agreement by consensus, the matter shall be referred to the OUR for determination. Any such referral to the OUR shall set out the cause of disagreement and the views held by the respective members.

The Review Panel may establish subcommittees from its members and co-opt other persons and experts as the Review Panel considers appropriate to assist in the review of requests or submissions from Users or developments in the Technical Standards, as it may require from time to time. The subcommittees shall present its dealing and recommendations to the Review Panel for further consideration and recommendation to the OUR, as applicable.

The Technical Standards are the sections of the Codes that imposes obligations such as those relating to Engineering Standards, System Operation Policy and procedures of the Licensee.

IC 11.5 Revisions of the Codes

The Office shall publish on its website or in any other manner that it considers appropriate the revised versions of the Codes as recommended by the Review Panel and approved by the Minister and the Minister.

All changes made to each of the Codes shall be logged in the Code Change Register which shall indicate the section which was amended and the reason for the change. The Code Change Register will be restarted if the OUR determines that the Codes are to be revised entirely.

The Review Panel and the System Operator shall retain a list of all Users that have made a written request to be informed of changes to the Codes and shall inform such Users electronically or in writing of any changes.

The System Operator shall also publish the revised Codes on its website along with the Code Change Register.

IC 12 NON-COMPLIANCE

IC 12.1 Granting of Derogation from Obligation

The OUR may, after consultation with the System Operator, issue a Derogation from Obligation suspending the System Operator's or a User's or a Generator's obligations to implement or comply with the Codes to the extent specified in the Derogation from Obligation; provided that the exercise of the power to issue such Derogation from Obligation is consistent with the provisions of applicable legislation.

IC 12.2 Request for Derogation from Obligation

A request for Derogation from Obligation from any provision in the Codes shall contain the following information:

a. The clause against which the present or predicted non-compliance is identified;

b. The reason for non-compliance with the provision;

c. Identification of the Apparatus in respect of which a Derogation from Obligation is being sought; and

d. Whether the Derogation from Obligation sought is permanent or temporarily for the purposes of achieving compliance. If temporarily for the purpose of achieving compliance, the date by which the non-compliance will be remedied.

IC 12.3 Derogation from Obligation for Existing Apparatus not in Compliance

Where at the Effective Date of the Codes, not all Apparatus in the System in use are able to meet the Technical Standards defined therein and where it is not reasonably economical or technically necessary to upgrade the existing Apparatus to meet the required standard, consideration should be given to a time bound Derogation from Obligation for all or part of the existing User's System or Systems.

IC 13 DISPUTE RESOLUTION

IC 13.1 Mutual Discussion

If a Dispute between the System Operator and a User or a Generator in Interconnection with, or arising out of, any clause in the Codes, either party may issue to the other party a Dispute Notice outlining the matter in Dispute. Following issuance of a Dispute Notice both Parties shall discuss in good faith and attempt to settle the Dispute between them.

IC 13.2 Submission to the Review Panel Discussion

Where the Parties fail to settle the Dispute amicably, either party to the Dispute may submit the Dispute to the Review Panel, which shall consider the Dispute and propose to the OUR within thirty (30) days, a revision to any aspect of the Codes that will resolve the Dispute.

Upon receipt of a proposed revision of the Codes from the Review Panel, the OUR shall indicate its approval or disapproval within thirty (30) days of receipt thereof and shall subsequently submit the proposed revision(s) to the Minister for approval.

Any such revision of the Codes shall determine the outcome of the Dispute.

IC 13.3 Determination by the OUR

Subject to sub-section IC 13.1 and any legally binding agreement between the Parties, if the Dispute cannot be settled within thirty (30) days after issue of the Dispute Notice, either party shall have the right to refer the Dispute to the OUR for resolution. In this case the procedure shall be as follows:

The request for referral to the OUR shall be made in writing to the OUR with the copy of the original Dispute Notice between the Parties attached.

Upon receipt of a request for referral, the OUR shall write to both Parties acknowledging that the Dispute has been referred to the OUR for resolution.

Following receipt of OUR acknowledgment, each party shall have five (5) working days to submit their reason(s) as to the cause of the Dispute in writing to the OUR.

No later than ten (10) working days after the OUR has received each party's reason(s) in writing, the OUR shall write to each Party setting out how the OUR intends to resolve the Dispute and indicate a date by which its determination of the Dispute may be expected which in any case shall not exceed three months from the date of the request for referral.

The determination by the OUR shall be legally binding on both Parties, subject to the right of either party to appeal such determination which shall be exercised in accordance with the provisions of the Electricity Act or the Electricity Licence.

IC 14 TRANSITIONAL PROVISIONS AND EXEMPTIONS

IC 14.1 Effective Date and Transition Period

The Codes shall come into operation on the Effective Date. However, a transition mechanism is required to enable the Licensee and Users to reconfigure current operations for compliance prior to full enforcement of all the provisions of the Codes. This section establishes (1) a transition period to enable full compliance by the Licensee and all Users; (2) a mechanism for the Licensee and Users to identify and seek time-limited derogations from OUR for non-compliant operations during the transition period; and (3) a requirement that the Licensee and Users seek to bring all PPAs and licences into compliance with the Codes. The intent is to bring all Parties into compliance with the Codes as soon as economically and technically feasible, to provide a uniform system applicable to the Licensee and all Users to support a safe and reliable Grid.

IC 14.2 Purpose and scope

The OUR recognizes that the Licensee and Users relied upon the existing Generation Code in construction and equipment installations in their current facilities, and in training their staff to meet the performance standards set forth in the existing Generation Code. Some of the facilities currently in operation do not meet all the required criteria set forth in the new Codes, and need to be accommodated as they transition to full compliance. Furthermore, the management systems and the human resources of the System Operator will need to be developed over a period of time to accommodate the functional unbundling of the System Operator from the Single Buyer and other Licensee functions under the Electricity Licence. Therefore, transitional arrangements and exemptions are needed to bridge these non-compliant facilities into compliance with the Codes.

The Licensee and Users who are unable to comply with the Codes will be required to submit a Request for Relief to the OUR, the details of which are described below. Once the Request for Relief is submitted, the OUR will, in consultation with the System Operator, review the request and may to the extent necessary issue a Transition Period Derogation Order. The Transition Period Derogation from Obligation Order may combine temporary reliefs and/or relaxation of standards, conditioned upon an acceptable plan to bring its equipment and installations into compliance and capacity building for personnel in response to changes in roles, obligations and responsibilities under the Codes.

IC 14.3 Request for Relief

In seeking relief from enforcement of Codes provisions during a transition period, there shall be a submission of a Request for Relief to OUR within ninety (90) days of the Effective Date of the Codes. Applicants are encouraged to contact and meet with OUR staff prior to submission to expedite final approval.

The Request for Relief must contain the following:

(1) a list of all assets, installations, and equipment owned or operated by the applicant which cannot comply with the Codes;

(2) a reasonably detailed description of the specific technical characteristics of the reasons that the assets, installations or equipment cannot meet the Codes; and

(3) a detailed plan to bring all assets, installations, and equipment into compliance with the Codes and to train all personnel in Codes compliance as soon as economically and technically feasible, but in all cases within two (2) years of the Effective Date of the Codes; and

(4) any additional information that the Applicant considers necessary for the OUR's assessment.

The OUR shall issue a Transition Period Derogation Order in response to a complete and acceptable Request for Relief, providing temporary relief and exceptions as required to enable a transition period for the applicant to come into compliance. The OUR, prior to issuing a Transition Period Derogation Order, shall consult with the System Operator.

The general framework for the Transition Period Derogation Orders shall be as follows:

Any non-compliance or deficiency in assets, installations or equipment noted in the Order will be treated as if compliant with the Codes during the term of the Derogation Order, so long as the Licensee or User remains compliant with the legislation, rules and licence provisions applicable immediately prior to the Effective Date.

If performance benchmarks are applicable to the Licensee or User, the corresponding performance benchmarks pursuant to the legislation, rules, and licence provisions in existence immediately prior to the Effective Date shall be applicable during the term of the Transition Period.

In response to an acceptable Request for Relief, the OUR shall issue a Transition Period Derogation Order for assets, installations and equipment that are in operation within the System on the Effective Date of the Codes authorizing continued operation as part of the System during a transitional period which shall not exceed twelve (12) months. Equipment and facilities not included in the Request for Relief shall be deemed fully compliant and subject to the provisions of the Codes.

IC 14.4 Existing Generation Facilities:

In response to an acceptable Request for Relief, the OUR shall issue a Transition Period Derogation Order for all generation equipment and facilities that are in operation and interconnected to the System on the Effective Date authorizing continued operation during a transitional period which shall not exceed twenty-four (24) months. Equipment and facilities not included in the Request for Relief shall be deemed to be fully compliant and subject to the provisions of the Codes.

IC 14.5 Existing Off-taker Facilities

In response to an acceptable Request for Relief, the OUR shall issue a Transition Period Derogation Order for all User facilities that are interconnected to the System on the Effective Date authorizing continued operation during a transition period which shall not exceed twenty-four (24) months. Equipment and facilities not included in the Request for Relief shall be deemed to be fully compliant and subject to the provisions of the Codes.

IC 14.6 Existing Contracts

Power Purchase and Interconnection Agreements existing on the Effective Date shall continue in force unless the contract is revoked or amended by agreement. The Codes shall apply to all such existing contracts insofar as the provisions thereof does not impair the obligations arising from the existing contract.

The OUR, the Minister or his designee(s) and the System Operator shall cooperate and consult with licensees to address any claims that a licence, Power Purchase Agreement or Interconnection Agreement prevents the application of the Codes to the licensee or in any other way exempts the licensee from complying with the Codes. The System Operator and Single Buyer shall ensure that contract entered into after the Effective Date conforms to all the provisions of the Codes, as amended from time to time, in order to attain uniform and non-discriminatory implementation of the Codes.

The System Operator shall not enter into a new contract or agree to extend any existing Power Purchase or Interconnection Agreements that is not in accordance with the Codes. The contracts shall ensure that licensees remain compliant with the Codes so as to assure the safe and reliable operation of the Grid.

IC 15 NOTICES

Notices and communique relating to the Codes should be directed to the following contact details.

		Address	Phone	Fax	Email
The Ministry	The Minister. I/C of Chief Technical Director	2nd Floor PCJ Building, 36 Trafalgar Road, Kingston 10	(876)929-8990-9	(876)960-1623	
Office of Utilities Regulation (OUR)	Director Regulation Policy Monitoring & Enforcement	3rd Floor PCJ Building, 36 Trafalgar Road, Kingston 10	(876) 968-6057	(876) 929-3635	ahewitt@our.org.jm
Single Buyer Jamaica Public Service Company Limited (Licensee)	Head, Government & Regulatory Affairs	6 Knutsford Boulevard, Kingston 5	(876) 935-3547	(876) 511-2027	sdavis@jpsco.com
Jamaica Energy Partners (JEP)	General Manager	RKA Building, 3rd Floor, Grenada Way, Kingston 5	(876) 920-1705	(876) 920-1750	
Jamaica Private Power Company (JPPC)	General Manager	110 Windward Road, Kingston 2	(876) 938-3983, 928-4532, 928-9404	(876) 938-3982	
Jamalco	Managing Director	13 Waterloo Road, Kingston 5	(876) 926-3390-5	(876) 926-6901	

Wigton Windfarm Limited	Managing Director	PCJ Building, 36 Trafalgar Road, Kingston 10	(876) 960-3994, 960-0568	(876) 960-3108	
Jamaica Broilers	Managing Director	McCook's Pen, St. Catherine	(876) 943-4376	(876) 943-4322	
West Kingston Power Partners (WKPP)	General Manager	RKA Building, 3rd Floor, Grenada Way, Kingston	(876) 920-1750	(876) 920-1750	
Blue Mountain Renewables Limited (BMR)	Managing Member	5 Penn Plaza, Suite 1974 New York, NY 10001			
WRB Energy and Content Solar Limited	President and CEO	1414 Swann Avenue, Suite 201, Tampa, FL 33606	(813) 251-3737	(813) 251-3788	
Eight Rivers Energy Company Limited	Managing Director	22B Old Hope Road Kingston 5			

APPENDIX A

TABLE OF DEFINITIONS AND ACRONYM

AC	Alternating Current
Active Power (W)	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.
Advanced Metering Infrastructure (AMI)	Metering Systems that measure, collect and analyse energy usage, from advanced electricity meters using various communication channels either on request or on a pre-defined schedule. The infrastructure includes hardware, software and communications.
Allowable Error	The error associated with metering equipment described in this Code which shall not exceed ±0.5% of full scale reading.
Ancillary Service	Those services necessary to support the transmission and distribution of electric power from seller to purchaser.
Apparent Power, (VA)	A unit of electric measurement, measured in Volt-Ampere (VA), or multiples thereof, equal to the product of a volt and an ampere that for the DC constitutes a measure of power equivalent to a Watt (W).
Authority for Access	Authority granted to a person(s) by the Single Buyer to enter its site without supervision.
Availability	The amount of time that the Generating Unit/Plant is able to produce energy over a certain period.
Average Conditions	That combination of observed values of weather conditions averaged over a long period of time.
Backup Metering System	The meters and metering devices owned by the Generator and used to measure the delivery and receipt of Net Energy Output, Dependable Capacity and other parameters.
Base load Unit	A Generating Unit designated to operate for more than 8000hour per annum and do not go through cycles of economic shutdown.

Black Start	The procedure necessary to recover from a total or partial shutdown.
Black Start Capability	The ability to restart the generating facility in the absence of incoming power from the grid.
Black Start Generating Unit	A Generating Unit with Black Start Capability.
Breaking Capacity	A value of prospective current that a switching device is capable of breaking at a stated voltage under prescribed conditions of use and behaviour.
BSJ	Bureau of Standards, Jamaica.
CDGU	Committed Dispatchable Generating Unit.
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.
Codes	The Generation, Transmission, Distribution, Despatch and Supply Codes collectively or any combination of more than one Code as developed by the Office and approved by the Minister with responsibility for electricity, from time to time.
Code Change Register	Register of all changes to the Transmission and Distribution Codes.
Code Review Panel	A panel established by the OUR to review the Codes in accordance with section IC 10 of the introduction to the book of Codes.
Cogeneration	The production of both useful heat and electrical power from a single generating source.
Co-Generator	A facility which simultaneously provides electrical and thermal energy from a singular fuel source for its process requirements as well as electrical output to the System.
Commercial Operation Date (COD)	The date at which all testing of a Generating Facility or a Generating Unit or a Transmission or Distribution System Development or a User Development is completed and is certified by the relevant party (e.g., Single Buyer, the System Operator, the Government Regulator or a User for commercial use with the System.

Commissioning	The systematic activities and process of documenting undertaken by the System Operator, the Single Buyer, User to prepare Plant, Apparatus, Equipment newly installed or retrofitted for connection to and operation within the System.
Commissioning Test	A test or a series of tests for establishing, by measurement, the characteristics of Plant or Apparatus or Equipment are in accordance with the specified Equipment standards and its fitness for interconnection to and safe,reliable ,continuous operation on the System without any adverse effects.
Completion Date	The date of energisation of the Interconnection Point.
Contingency Reserve	The margin of generation over forecast Demand which is required in the period from 24 hours ahead down to real time to cover against uncertainties in Generating Unit(s)' availability and against both weather forecast and Demand forecast errors.
Control Person	A person who has been nominated by an appropriate officer of the System Operator or a User to be responsible for controlling and co-ordinating safety activities necessary to achieve safety on the System.
Corporate Area	That portion of the System Grid that serves Kingston and St. Andrew.
Critical Fault Clearing Time (CFCT)	The maximum fault duration (time) for which the System remains for the System remains Transiently stable remains transiently stable.
Current Transformer (CT)	A device which has its primary winding connected in series with the current to be measured and a secondary winding which provides a current proportional to the primary current at a range suitable for measurement or control.
Customer(s)	Any person or entity supplied with electricity service under a contract with the Supply Licensee.
Customer Demand Management	The reduction in the supply of electricity to a Customer or the disconnection of a Customer in a manner agreed.

Cycling Units	A Generating Unit required to operate less than 8000 hours per annum and designed to withstand cycle of economic shut down and start up.
Day	The 24 hour period beginning and ending at 00:00 hours Eastern Standard Time.
DDR	Dispatch Data Recorder.
Dead band	An interval of a signal domain or band where no action occurs.
Dead Bus Control	Connecting a Generating Facility to a de-energised grid and having it perform frequency and voltage control.
Demand	The Demand of MW or MVAR of electric power (i.e. both Active and Reactive Power respectively) unless otherwise stated.
Demand Interval	The period over which the Demand is integrated.
Dependable Capacity	The maximum Capacity modified for ambient limitations which a Generating Unit, or item of electrical equipment can sustain over a specified period of time.
Derogation of Obligation	A waiver issued by the OUR after consultation with the Grid Operator, suspending the Grid Operator's or a User's obligations to implement or comply with the requirements of the Codes.
Discount Rate	The percentage by which the value of a cash flow in a Discounted Cash Flow (DCF) valuation is reduced for each time period by which it is removed from the present.
Discounted Cash Flow	A method of evaluating an investment by estimating future cash flows and taking into consideration the time value of money.
Despatch	The activities involved in the central management and direction of generating plants and other sources of supply to the System in order to achieve the optimal safety, reliability and economic supply of electricity.
Despatch Activities	The activities involved in the central management and direction of generating plants and other sources of supply to the System in order to achieve the optimal safety, reliability and economic supply of electricity.
Despatch Code	The rule made by the Office, and approved by the the Minister, to govern Despatch Activities.

Despatch Licensee	A person holding an electricity licence to conduct dispatch activities.
Despatch Instructions	The instructions issued by the Grid Operator from System Control Centre to the Generator to schedule and control its Generation in order to increase or decrease the electricity delivered to the System.
Despatchable Generating Units	Generating Units whose required level of output at any instant of time is determined and regulated by the System Control Engineer.
Dispute	Any controversy or difference between the System Operator and any User or a Generator in Interconnection with, or arising out of, any clause in the Codes.
Dispute Notice	A written notice issued by either Party to a Dispute outlining the matter in Dispute.
Distribution	The conveyance of electricity by means of distribution lines, which are electric power lines operating below 69 kV.
Distribution Code	The rules made by the Office, and approved by the Minister, to govern the distribution system and activities relating thereto.
Distribution Code Technical Standards	The Technical Specifications applicable/implemented to govern the technical development and operation of the Distribution System as listed in section DC 7.2
Distribution Licensee	The Person having an electricity licence to establish, maintain and operate the Distribution. For the avoidance of doubt, the Transmission Licensee includes [does not include]a User who owns and operates a User System
Distribution Lines	Any electric power lines operating below 69,000 volts
Distribution System	That part of the electric System that operates below 69kV from the point of the outgoing isolators of a Feeder - Circuit Breaker (recloser) at transmission substations transforming to 24kV, 13.8kV and 12kV, consisting of Apparatus and meters owned and operated by the System Operator used in Interconnection with the distribution of electricity.
Earth Fault Factor	At a selected location of a three-phase system (generally the point of installation of equipment) and for a given system configuration, the ratio of the highest root mean square phase-to earth power frequency voltage on a sound phase during a fault to earth

	(affecting one or more phases at any point) to the root mean square phase-to-earth power frequency voltage which would be obtained at the selected location without the fault.
Economic Dispatching Technique	The approved method used to rank Generating Units by their economic merit and to determine at which level they should be dispatched to minimize total variable operating cost subject to Generating Units operating limits and system constraints.
Effective Date	The day appointed by the Office by notice published in the Gazette.
Electrical Inspector	A suitably qualified person licensed by the Minister
Electricity Act	Refers to the Electricity Act, 2015 promulgated 2015 August 27
Electricity Licence	Refers to the Electricity Licence, 2016 promulgated 2016 January 27 issued to JPS by the Government of Jamaica authorizing JPS to generate and exclusively transmit, distribute and supply electricity in the island of Jamaica for public and private purposes.
Embedded Generating Facility	A Generating Facility that is connected to a Distribution System that has no connection to the Transmission System.
Embedded Generating Plant	Any facility whether privately or JPS owned containing one or more Embedded Generating Units and associated infrastructure producing and delivering electrical energy to the Distribution System and has no Interconnection to the Transmission System.
Embedded Generating Unit	An individual Generating Unit which is part of an Embedded Generating Plant.
Embedded Generator	A person or entity that generates electricity using an Embedded Generating Plant which can be a VRPP or conventional generating plant.
Emergency Operation Centre	The main control Centre for the operation of the System during emergency conditions (post hurricane restoration).
Energy Management System (EMS)	The **system** of computer-aided tools used by the System Operator to monitor, control, and optimize the performance of the generation ,Transmission and Distribution System.

Entry Point	The point at which Users connect to the Transmission System where power flows into the Transmission System.
Equal Incremental Cost Principle	The Equal Incremental Cost Principle relates to the economic dispatch of power generation where each Generating Unit on line, should operate at the same System wide point of Incremental Cost to serve a given load.
Equipment	Plant and/or Apparatus.
Exit Point	The point at which Users Interconnect to the Transmission System where power flows out of the Transmission System.
Fault Level	The expected current, expressed in kA or Fault MVA, which will flow into a short circuit at a specified point on the Distribution System or any Users System.
Feeder	Means an MV electric line(s) and associated MV Equipment which the Grid Operator uses to distribute electricity from a power source.
Force Majeure	Causes beyond the reasonable control of and without the fault or negligence of the Party claiming Force Majeure. It shall include failure or interruption of the delivery of electric power due to causes beyond that Party's control, including acts of God, wars, sabotage, riots, hurricanes and other actions of the elements, civil disturbances and strikes.
Forced Outage	An interruption of a Generating Unit's capability to generate power that is not the result of (i) a request by the Grid Operator (ii) a Scheduled Outage or a Maintenance Outage; or (iii) an event or occurrence of Force Majeure.
Frequency Dead Band	The range of deviations of system frequency (+/-) that produces no Primary Frequency Response.
Fuel Supply Agreement	The Agreement for providing fuel to ensure its operation in accordance with the terms and provisions of this Code or any contracted Power Purchase Agreement. The Fuel Supply Agreement shall include, but not be limited to, the Generator's proposed fuel specification, fuel supply and transportation arrangements, and the Generator's plans to obtain fuel on the most economic basis at any given time.

Full Load Point	The declared maximum capacity pursuant to the most recent Dependable Capacity Test (DCT) consistent with respective PPA conditions.
Full Load Rejection	The loss of demand that is equivalent to the full load rating of a generating unit that is separated from the Grid at the time when the unit is operating at full load.
Generating Unit	Any electric power generating Plant or Apparatus, whether privately or Licensee owned, delivering electrical energy to the Transmission or Distribution System.
Generating Plant	Any facility whether privately or Licensee owned containing one or more Generating Units and associate infrastructure producing and delivering electrical energy to the Transmission or Distribution System.
Generation	The production of electricity by means of a Plant or Apparatus.
Generation Code	The rules made by the Office, and approved by the Minister, to govern Generation activities in the electricity sector.
Generation Licensee	A person having an electricity licence issued by the Minister to conduct the activity of generating electricity in Jamaica.
Generator	Owner and/or operator of an electricity Generating Plant, supplying power to the System Operator.
Government Electrical Regulator	The entity responsible for regulating the work of Electricians and Electrical Inspectors.
Grid	Used interchangeably with the term “System”.
Guaranteed Standards	As required by Condition 17 of the Electricity Licence.
Harmonics	A sinusoidal wave having a frequency that is an integral multiple of a fundamental frequency.
Harmonic Distortion	Harmonic distortion is the departure of a waveform from sinusoidal shape that is caused by the addition of one or more harmonics to the fundamental.

Heat Rate	The measure of a Generating Unit's thermal efficiency, expressed as the number of thermal energy units to produce one kWh of electrical energy.
Heat Rate Curve	A plot of Heat Rate changes between minimum and maximum output levels of a Generating Unit.
Heat Rate Test	A test of a Generating Unit's thermal efficiency carried out in accordance with sub-section GC 12.2.3 of the Generation Code.
High Voltage (HV)	The parts of the System operating at 69kV and above.
Incident	An unscheduled or unplanned (although it may have been anticipated) occurrence on the Transmission or Distribution System or Users' System, including, without limiting that general description, faults, incidents and breakdowns and adverse weather conditions being experienced.
Incident Centre	A Centre established as determined by the System Operator following a Significant Incident to provide a focal point for communication and the dissemination of information between System Operator and representatives of relevant Users.
Incremental Cost	The cost required to produce an additional MWh of energy above a base amount. (see Sub-section DSC 7.3.3).
Independent Engineer	The independent licensed professional engineer jointly selected by the Parties who, among other things, shall receive copies of all test results performed pursuant to Section GC 12.2 of the Generation Code, on the Generating Facility for the purpose of certifying in writing that the Facility can be satisfactorily commissioned. The fees charged by the Independent Engineer shall be borne by the Generator.
Independent Power Producer (IPP)	Any private Generator other than JPS selling power to the Single Buyer.
Integrated Resource Plan (IRP)	A comprehensive decision support tool and road map for meeting Jamaica's objective of providing electric service to all customers which desire the service while addressing the substantial risks and uncertainties inherent in the electric utility business.
Interconnection	The connection of a transmission or distribution line between the generation assets of a generation licensee or a Self-Generator and the transmission system or the distribution system respectively.

Interconnection Agreement	An agreement between the System Operator and a Generator or User providing for the Interconnection of the Generating Unit or User plant to the Transmission System.
Interconnection Point	The physical point(s) where the Generator and the System Grid are connected as specified in Sub-section GC 2.1 of the Generation Code.
Interconnection Related Planning Studies	Power flow simulations, short circuit and stability studies performed as necessary to determine the requirements for the Interconnection of loads to the System to ensure the security and reliability of the System.
Interconnection Site	The physical site belonging to the System Operator, Generator or User where a Interconnection Point is located.
IPP	Independent Power Producer.
JANAAC	Jamaica National Agency for Accreditation.
Joint System Incident	An Incident which, in the opinion of the System Operator or a User, has or may have a serious and/or widespread effect on the Transmission System, Distribution System or on a User System.
JPS	Jamaica Public Service Company Limited. Currently the holder of the Electricity Licence, the Single Buyer and the System Operator.
JPS Guide To The Interconnection Of Distributed Generation	The document prepared by JPS that establishes the criteria and requirements for the interconnection of Embedded Generators, as revised from time to time.
kW	Kilowatts.
kWh	Kilowatt hours.
Large Customer	Customers who by virtue of the magnitude or characteristics of their Demand are connected directly to the Transmission System.
Licence	The Electricity Licence 2016 issued to JPS.
Licensee	The holder of the Electricity Licence 2016, currently JPS.
Licensee Guide To The Interconnection Of Distributed Generation	The document prepared by Licensee that establishes the criteria and requirements for the interconnection of Embedded Generators, as revised from time to time.

Large Customer	Customers who by virtue of the magnitude or characteristics of their Demand are connected directly to the Transmission System.
Load	Demand in watts or multiples thereof.
Load Shedding	The automatic or manual disconnection or interruption of the electrical supply to a customer Load by the utility, usually to mitigate the effects of generating Capacity deficiencies or Transmission limitations.
Local Safety Procedures	Procedures at each Interconnection Point approved by the System Operator or the relevant User setting out the methods to achieve safety for those working on Plant and Apparatus to which their Safety Rules apply.
Low Voltage (LV)	The parts of the System operating at 415V and less.
Making Capacity (of a switching device or a fuse)	A value of prospective fault current that a switching device is capable of making at a stated voltage under prescribed conditions of use and behaviour.
Maintenance Outage	An interruption or reduction of the Generating Unit capability that: i. is not a Scheduled Outage; or ii. has been scheduled and allowed by the System Operator in accordance with Section 5; and iii. is for the purpose of performing work on specific components, which work could be postponed by at least six (6) Days but not be postponed until the Scheduled Outage.
Maximum Demand (MD)	The maximum measured value of Demand that occurs within a specified time period. (e.g. Month, Year)
MBTU	1 million British Thermal Unit. One BTU is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Fahrenheit.
Medium Voltage (MV)	The parts of the System operating at voltages above 415V and below 69kV.
Metering Point	The point of Interconnection of the terminals of a whole current meter or the point of the Current Transformers for CT metering.

Metering System	All meters and metering devices (including the Primary and Backup Metering Systems) used to measure the delivery and receipt of Net Energy Output, Dependable Capacity and other parameters pursuant to Section GC 3 of the Generation Code.
Minister	The Minister with portfolio responsibility for Electricity.
Month	A calendar Month according to the Gregorian calendar beginning at 00:00 hours Eastern Standard Time on the last day of the preceding Month and ending at 00:00 hours Eastern Standard Time on the last Day of that Month.
the Ministry	Ministry of Science Energy and Technology.
MVA	Megavolts Amperes.
MVAR	Megavolts Amperes Reactive.
MW	Megawatt.
MWh	Megawatt hour.
N-1	The loss of any single element (such as an electric line, transformer etc.) from the Transmission System or Distribution System.
Net Billing	Means a mechanism for self-generators to sell or be otherwise credited with the value for the excess power generated under standard offer contracts with the Single Buyer that have been approved by the Office.
Net Energy Output	Net energy delivered by the Generator for sale to the Grid Operator at the Interconnection Point in accordance with a valid Dispatch Instruction.
Nominal Operating Voltage	Voltage that is required electrically at any point of the System Grid.
Non-Dispatchable Generating Units	Generating Units will be classed as Non-Dispatchable when it is not practical to control or dictate the required level of output of these units to the system Grid on an ongoing basis.
Non-Spinning Reserve	That reserve in MW not connected to the System but capable of serving Demand within a specified time..
Operating Margin	The amount of reserve, provided by Generating Units or by Demand control, available over and above that required to meet the expected Demand. It is required to limit and then correct

	frequency deviations that may occur due to an imbalance between total generation capacity output and Demand.
Operating Reserve	Generating capability in MW above firm System Demand available to provide for regulation, load forecasting error, equipment forced and scheduled outage. It consists of Spinning and Non Spinning Reserve (Generation Code).
Operation	A scheduled or planned action relating to the operation of the System or a User System.
Operation Diagram	Diagrams which are a schematic representation of the HV and MV Apparatus and the connections to all external circuits at a Interconnection Site (Point), incorporating its numbering, nomenclature and labelling.
Operational Effect	Any effect on the operation of the Transmission System which will or may cause the Transmission System or the User's system, as the case may be, to operate adversely from the way in which they would or may have operated in the absence of that effect.
Operational Interface	The common boundaries of the User and System Operator Interconnection Sites.
Operations Log	A record of significant operating events, plans, requests and instructions.
OUR (Office)	Office of Utilities Regulation established pursuant to the Office of Utilities Regulation Act.
Overall Standards	As required by Condition 17 of the Electricity Licence.
Partial Load Rejection	The partial or complete loss of power Customers without the separation of a generating unit from the grid with the generating unit initially operating at full load.
Party	The System Operator and all Users of the System.
Parties	System Operator and all Users of the System.
Peak Hours	The hours between 5:00 pm and 9:00 pm Eastern Standard Time every day of the week.
Plant	Fixed and moveable items used in the generation, transmission or distribution of electricity other than Apparatus.

Point of Common Coupling (PCC)	The closest point on the System Operators side of the User's Interconnection Point where another User is or could be connected.
Power Island	A group of Generating Units together with complementary local Demand, disconnected from any other power source or the Total System.
Power Purchase Agreement (PPA)	The contract that governs the commercial relationship between an IPP and the Single Buyer which is approved by the OUR and that requires the Single Buyer to buy electricity from the IPP and the IPP to sell electricity to the Single Buyer in accordance with the terms and conditions thereof.
Power Quality Policy	The System Operator's policy document that outlines the parameters, standards and normal operating limits relevant to power quality, to be developed by the System Operator, approved by the OUR and as amended from time to time.
Primary Frequency Response (PFR)	The instantaneous proportional increase or decrease in real power output provided by a Resource and the natural real power dampening response provided by Load in response to system frequency deviations. This response is in the direction that stabilizes frequency.
Primary Metering System	All meters and metering devices (financed by the Generator but owned by the Grid Operator) used to measure the delivery and receipt of Net Energy Output, Dependable Capacity and other parameters pursuant to Section GC 3 of the Generation Code.
Prudent Utility Practice	The practices generally followed by the electric utility industry in respect to the design, construction, operation, and maintenance of electric generating, transmission, and distribution facilities, including, but not limited to, the engineering, operating, and safety practices generally followed by such utility industries.
Qualifying Entity or QF	A residential or non-residential entity which is the legal owner of the QF
Qualifying Facility or QF	An approved intermittent renewable energy system with nameplate capacity less than or equal to 100 kW
Rapid Start	The ability for a Generating Unit to be started and synchronized in less than 10 minutes after an instruction is given to do so by the grid operator.

Rated Capacity	A measure of the ability to generate electric power continuously usually expressed in Megawatts or kilo Watts.
Reactive Power (VAR)	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 the sum of the Reactive Power of the Individual phases.
Registered Capacity	The normal full load capacity of a Generating Unit or Embedded Generating Unit as declared by the Generator or Embedded Generator respectively, less the MW consumed by the Generating Unit or Embedded Generating Unit through auxiliary/unit transformers when producing at full load. It is expressed in MW or kW.
Renewable Energy Source	Energy sources that are not depleted when exploited and includes sources prescribed by the Minister by order published in the Gazette.
RME	Remote monitoring equipment.
Rural Area	Area of Jamaica that does not fall within the Corporate Area.
Rural Electrification Project	Works undertaken by the Rural Electrification Programme Limited (REP) under Condition 26 of the Electricity Licence.
Safety Coordinator	A person nominated by the System Operator and each User in relation to a Interconnection Point to be responsible for the coordination of safety precautions when work is to be carried out which requires the provision of safety precautions on Apparatus.
Safety Management System	The procedure adopted by the System Operator or User to ensure the safe Operation of the System and the safety of personnel required to work on the System.
Safety Rules	The rules or procedures of the System Operator or User to ensure safety of persons working on or testing Apparatus from the dangers inherent in working on or testing Apparatus that forms part or is connected to the Transmission or Distribution Systems.
SCADA	Supervisory Control And Data Acquisition.

Scheduled Outage	A planned interruption of the Generator's generating capability that: i. is not a Maintenance Outage; ii. has been scheduled and allowed by the Grid Operator in accordance with Section 5; and iii. is for inspection, testing, preventive maintenance, corrective maintenance or improvement.
SDP	Scheduling and Dispatch Parameters.
Self-Generator	A person who generates electricity for that person's own exclusive use, and shall include a person who has entered into a Net Billing or Power Wheeling arrangement.
Sequence of Events	Record of power system activities with respect to time.
Service Area	A section of the Distribution System supplied by one or more substation bus bars and/or Feeders of the same MV level.
SF6	Sulphur Hexaflouride Gas used for the insulation of HV and MV Equipment.
Short Circuit Ratio **(SCR)**	The ratio of the field current required for the rated voltage at open circuit to the field current required for the rated armature current at short circuit for synchronous Generating Units.
Significant Incident	An Incident which in the opinion of the System Operator has had a significant effect on the Transmission or Distribution System or the User System.
Single Buyer	The licensee whose license obligates it to purchase electricity generated by independent power producers and persons having net billing, power wheeling, or auxiliary interconnection arrangements.
Site Common Drawings	Drawings prepared for each Interconnection Site (Point) which incorporate Interconnection Site layout drawings, electrical layout drawings, common protection/control drawings and common services drawings.

Site Investigation Tests	Tests conducted in relation to Plant, Apparatus and Operational Procedures at Generation Facilities and User Sites or to monitor and assess the characteristics of Plant.
Spinning Reserve	Unloaded generating capacity in MW which is synchronized and ready to serve additional Demand as set forth in the Generation Code.
Standard Offer Contract	A contract developed and approved by the Office for use in promoting renewable energy with capacity limits established by the Minister under a Net Billing arrangement.
Subdivision	An area of real estate composed of subdivided lots.
Substation	Grouping of equipment inclusive of transformers, circuit breakers, switches and protective devices used to facilitate among other things the transformation of voltages and switching operations. A combination of generation, transmission, and distribution components within a specially defined area.
Supply	Activities involved in the sale of electricity to Customers.
Supply Code	The rules made by the Office, and approved by the Minister to govern the supply of electricity and activities relating thereto to Customers.
Supply Licensee	A person having a licence issued by the Minister to conduct the activity of supplying electricity to Customers throughout Jamaica.
System	The interconnection facilities and any other Transmission System or Distribution System, transmission or distribution facilities on the System Operator side of the Interconnection Point(s) through which the electrical energy output from the Generating Unit(s) will be distributed by the System Operator to Users of electricity. (See Generation Code). The terms "Grid" and System" have identical meanings and are used interchangeably.
System Control	The administrative and other arrangements established to maintain as far as possible the proper safety, security and economic operation of the System.
System Control Centre	The main control Centre of the System Operator located in Kingston, Jamaica, or such other control Centre designated by the System Operator from time to time (but not more than one at any

	time) from which the System Operator shall issue dispatch instructions to the Generators.
System Control Engineer	Person appointed by the Systemj Operator and on duty at System Control Centre with responsibility for controlling the generation, transmission and distribution of electrical energy.
System Emergency	A condition or situation that, materially and adversely, or is likely to materially and adversely; (i) affect the ability of the Grid Operator to maintain safe, adequate and continuous electrical service to its customers, or (ii) endanger the security of person, plant or equipment.
System Grid	The Interconnection Facilities and any other transmission or distribution facilities on the System Operator' side of the Interconnection Point(s) through which the electrical energy output from the Generating Unit(s) will be distributed by the Grid Operator to users of electricity.
System Incident	An event on a part of the System or a User System that has an adverse effect on the rest of the System or other User System
System Incident Communications Procedures	Procedures agreed between the System Operator and Users to ensure secure communications during System Incidents.
System Operator (SO)	The licensee holding the dispatch licence; "transmission code" means the rules made by the Office, with the approval of the Minister, to govern the transmission system and activities relating thereto.
System Restoration Strategy	The strategy setting out the procedures for the restoration of the System following a major Incident.
System Test	A test or series of tests involving the simulation of conditions or the controlled application of unusual or extreme conditions which may have an impact on the Transmission, Distribution or User Systems.
Synchronization	The controlled interconnection of System facilities to operate in phase at the same frequency and voltage.
Technical Standards	All Standards as outlined in section xxx or any other acceptable benchmark or method as defined or in use by the Grid Operator.

Ten Minute Reserve	An additional amount of Operating Reserve sufficient to reduce generation deficiency within ten minutes following the loss of generating capacity (See Generation Code).
Test Document	The document prepared by the Test Panel setting out all aspects for the management and implementation of a test.
Test Panel	A panel established to prepare a detailed programme for the conduct of an operational test or Site Investigation and to prepare a formal Test Document.
Test Request	A document setting out the detailed proposal for an operational test or Site Investigation Test
Total System	The Transmission and Distribution Systems together with all User Systems.
Total System Shutdown	The situation when all generation connected to the Total System has ceased and the Total System has ceased to function.
Transient Stability	The inherent ability of a power system to remain stable and maintain network synchronism when subjected to severe disturbances
Transmission	The conveyance of electricity by means of transmission lines which are electric power lines operating at 69 kV or higher
Transmission Code	The rules made by the Office, and approved by the Minister, to govern the transmission system and activities relating thereto
Transmission Code Technical Standards	Technical specifications applicable/implemented to govern the technical development and operation of the Transmission System
Transmission Constraint	A limitation on the use of the System due to lack of transmission capacity or other System conditions.
Transmission Licensee	The Person having a licence issued by the Minister, to establish, maintain and operate the Transmission System.
Transmission Lines	Electric power lines operating at 69,000 volts or higher.
Transmission Security Standards	The standards set out in this Transmission Code by which the System Operator shall plan and operate the Transmission System to ensure a reliable and secure supply of electricity to Customers.
Transmission Site	A site owned (or occupied pursuant to a lease, licence or other agreement) by the System Operator in which there is a

	Interconnection Point. For the avoidance of doubt, where a site is owned by a User but occupied by the System Operator, the site is a Transmission Site.
Transmission System	That part of the electric System from the HV side of the Generating Unit Step Up (GSU) transformer that operates at 69kV or higher, and includes the Equipment on the secondary side of transformers at transmission substations transforming to 24kV, 13.8kV and 12kV up to the outgoing Isolators of the Feeder - Circuit Breaker (recloser), and consists of electric lines, Equipment and meters owned and operated by the Transmission Licensee in Interconnection with transmission of electricity. [This does not include a User System.]
Under Frequency Relay	An electrical measuring relay intended to operate when its characteristic quantity (frequency) reaches the relay settings by a decrease in frequency.
Under Voltage Relay	An electrical measuring relay intended to operate when its characteristic quantity (voltage) reaches the relay settings by a decrease in voltage.
Unit Controller	Person designated by the Generator to oversee the operation of any of the Generating Units and to liaise with System Control Engineer in this process.
Unit Commitment Schedule	The sequence of start up and shutdown times of thermal Generating Units which minimizes the total production cost including start up and shutdown costs over a period of at least 24 hours or up to a week, given the load forecast, and taking into account the Maintenance Schedule, generation reserve requirement and System security.
User(s)	Term used to refer to any person using the Transmission System or Distribution System, as more particularly identified in each section of the respective Code. In the Introduction and General Conditions the term means any person (other than Licensee) to whom the Codes applies.
User Site	A site owned (or occupied pursuant to a lease, Licence or other agreement) by a User in which there is a Interconnection Point. For the avoidance of doubt, where a site is owned by the Transmission System or Distribution System owner but occupied by a User the site is a User Site.

User(s)' System	The Transmission System or Distribution System owned and operated by a User, as opposed to a Transmission Licensee.
VAR-hour (VARh)	A unit of electric measurement, measured in reactive volt-ampere hour (VARh), or multiples thereof, of Reactive Power of one VAR integrated over one hour.
Variable Operating Cost (VOM)	Costs that vary with production of electricity. Variable Operation and Maintenance cost A period of seven (7) consecutive Days beginning at 00:00hours Eastern Standard Time falling between a Saturday and a Sunday.
Variable Renewable Power Plant (VRPP)	Renewable Energy Power Plant with continuously varying power output following the availability of primary energy without any storage (wind and solar PV).
Voltage Flicker	Voltage Flicker is the rapid change in voltage that distorts or interferes with the normal sinusoidal voltage waveform of the Transmission and Distribution Systems.
Voltage Transformer (metering)	A device which has its primary winding connected in shunt with the power circuit to be measured and a secondary winding which provides a voltage proportional to the primary voltage at a range suitable for measurement or control.
Watt-hour (Wh)	A measure of the electrical energy equivalent to a power consumption of one watt of Real Power for one hour, measured in watt-hour (Wh) or multiples thereof.
Week	A period of seven (7) consecutive Days beginning at 00:00 hours Eastern Standard Time falling between a Saturday and a Sunday.
Wheeling	An arrangement whereby a Self-Generator provides electricity to the system on terms pursuant to which an equivalent amount of electricity may be used from the system at one or more locations, in accordance with the Electricity Act and any regulations thereunder.
Review Panel	Refers to the Code Review Panel established by the Office.

X/R Ratio	The amount of reactance X divided by the amount of resistance R which is the same as the tangent of an angle created by reactance and resistance in an AC circuit.
Year	Each twelve (12) Month period commencing on 00:00 hours Eastern Standard Time on December 31 and ending on 00:00 hours Eastern Standard Time the following December 31 during the term of this Code.

APPENDIX B

TABLE OF TECHNICAL STANDARDS

	Source	References
1	D & T	ANSI C12.1 2008 – The Electric Meters code for Electricity Metering
2	D	ANSI C12.1 2008 – The Electric Meters code for Electricity Metering
3	D	ANSI C12:10 2004 – Physical aspects of watt-hour meters - safety Standard
4	D & T	ANSI C12:10 2004 – Physical aspects of watt-hour meters - safety Standard
5	D	ANSI C12:20 2002 – Electricity meters 0.2 and 0.5 accuracy Classes
6	D & T	ANSI C12:20 2002 – Electricity meters 0.2 and 0.5 accuracy Classes.
7	G, D & T	ANSI Standard C12.11
8	G, D & T	ANSI Standard C57.14
10	T	Engineering Instruction 1.11 - Planned Outage Procedure;
11	T	Engineering Instruction 2.2 – Hurricanes, Earthquakes and Civil Disturbances – Procedure for the Protection of Company Plant and Property
12	T	Engineering Instruction 2.8 – Reporting of Damage to Major Substation Plant
13	T	Engineering Instruction 4.7 Revenue Metering
14	D & T	Engineering Instruction Manual, Instruction No. 4.7 – Revenue Metering
15	T	Engineering Instruction No 1.6 – Load Shedding associated with Generating Plant Deficiency
16	D	Engineering Standard 1300 Section 1.2.3 – Voltage Regulation
17	D	Engineering Standard 1300 Section 2.7 – Grounding Regulations
18	D	Engineering Standard 1300 Section 2.8 – Transformers
20	G	IEEE Guidelines 37.102.2006
21	G	IEEE Guidelines 37.91.2000

Key

G: Licensee Generation Code

T: Licensee Draft Transmission Code

D: Licensee Draft Distribution Code

Generation Code

GC

GC 1 SCOPE

This Generation Code sets out the procedures and principles governing the operation of the Jamaica Electricity System and all interconnected Generation Facilities.

GC 2 INTERCONNECTION CONDITIONS

This section specifies the normal method of interconnection and the minimum technical, design and operational criteria which must be complied with by any Generator and prospective Generators including those with Variable Renewable Power Plant.

Additionally, details specific to each Generator's interconnection may be set out in a separate Interconnection Agreement or in some cases, the relevant Power Purchase Agreement. The Interconnection Conditions set out in the Code shall be read in conjunction with either or both of these Agreements as relevant. In the event that, there is any conflict between the provisions of the Code and any Interconnection Agreement and/or Power Purchase Agreement and the said Interconnection Agreement and/or Power Purchase Agreement was signed before the present Code came into effect, then, the provisions of the Interconnection Agreement and/or Power Purchase Agreement will supersede the Code. The foregoing, all Interconnection Agreements and/or Power Purchase Agreements shall be read in conjunction with the Code in force at any material time and in accordance with sub-section 2.1 of this Code.

GC 2.1 Method of Interconnection

The method of interconnection shall be determined on the basis of several technical and economic factors which include:

a. proximity to System;

b. Generating Unit (MW) rating or Generating Facility (MW) capacity;

c. Supply voltage;

d. Reliability considerations;

e. Auxiliary power supply;

f. Substation configuration

g. protection systems/devices; and

h. costs

It will not be technically or economically practicable to achieve uniformity of the method of interconnection. In all cases however, Prudent Utility Practice will guide the method adopted.

The method chosen by the Generator shall be reviewed and approved by the System Operator on the grounds of System security, stability and safety.

GC 2.1.1 Interconnection Point

The Generating Unit(s) shall be interconnected to the System via a Substation. The Interconnection Point shall normally be on the High Voltage side of the generator step-up transformer and will demarcate the boundary of responsibility between the Generator and the System Operator.

Generators, with capacity of 60 MW or more shall be interconnected to the switchyard/substation to satisfy the N-1 security criteria. This implies that the loss of any single Transmission element connecting a Generator to the Transmission System shall not result in a loss of generating capacity greater than 60 MW.

The finalized number of Interconnection Points shall be determined by a system analysis study at the time of interconnection to the System.

The Generator shall be responsible for all costs related to interconnection to the System.

GC 2.1.2 Supply Voltage

The voltage level at which the Generating Unit(s) are Interconnected to the System will be dependent on but not limited to the size and number of units and the other factors that determine the Interconnection Point.

Subject to other technical considerations, Generating Units with a Rated Capacity of 10 MW or above shall be interconnected to the Transmission System at 69 kV or 138 kV.

Generating Units with a Rated Capacity of below 10 MW may be interconnected to either the Transmission System at 69 kV or 138 kV or the primary Distribution System at 24 kV or less.

Embedded Generating Facilities with Rated Capacity between less than 1MW and 10MW may be interconnected via a dedicated feeder recloser from the Substation to the Facility.

GC 2.1.3 Configuration of Generation Substations

All Generation Substations shall have the capability to disconnect or separate, from the System, any transmission line and Generating Unit which is interconnected to the Substation.

For reasons of ensuring safety and reliability of operation, Generation Substations with more than three Transmission Lines and Generating Units interconnected to them shall be of a 'breaker and a half' configuration. The size of the Generating Units shall be considered for applicability of the breaker and a half requirement. The Substation shall be equipped with all requisite protection measures necessary to meet the System Operator's System protection standards as set out in sub-section GC 2.2.4.

GC 2.2 Generator Performance Standards and Technical Criteria

GC 2.2.1 Technical Standards

All components of the interconnection shall be constructed, installed and tested in accordance with the current edition at the time of construction of the following codes and standards, or their international equivalents and Prudent Utility Practice:

ACI	American Concrete Institute
ANSI	American National Standards Institute
ASCE	American Society for Civil Engineers
AME	American Society for Mechanical Engineers
ASNT	American Society for Non-Destructive Testing
ASTM	American Society for Testing Materials
AWS	American Welding Society
UL	Underwriters Laboratory
IEC	International Electro-technical Commission
IEEE	Institute of Electrical and Electronic Engineers
ISO	International Organization for Standardization
NBC	National Building Code (Jamaica)

NIST	National Institute of Standards and Technology
NEC	National Electric Code
NEMA	National Electric Manufacturers Association
NESC	National Electric Safety Code
NETA	National Electric Testing Association
NFPA	National Fire Protection Association
SSPC	Steel Structures Painting Council
BSJ	Bureau of Standards Jamaica
NEPA	National Environmental Planning Agency (Jamaica)
OSHA	Occupational Safety and Health Administration

GC 2.2.2 Performance Standards

Each Generating Unit interconnected to the System shall be required, as a minimum, to meet the following performance standards:

Sustained operation at any Load within the loading limits within the System frequency range of 49.5 Hz to 50.5 Hz;

a. Emergency operation within the Generator loading limits and within the system frequency range of 48.0 Hz to 52.5 Hz;

b. Maintain normal rated output at the System normal voltages specified sub-section GC 2.3 of this Code;

c. Sustained operation at the rated Power Factor set out in the relevant and appropriate Interconnection Agreement; and

d. System Interconnection Criteria (Schedule E of Appendix A)

GC 2.2.3 Station Capabilities

a. Synchronizing Facilities Each Generating Unit shall be equipped with synchronizing facilities to ensure Synchronization with the System. Two independent synchronizing facilities, preferably one automatic and one manual shall be provided, however, the primary must be automatic. The Synchronization facilities shall include a synchronism check relay to support synchronization under the following range of conditions:

i. System frequency within the limits 48.0 to 52.5 Hz; and

ii. System voltages within the limits specified in sub-section 2.3.

b. Auxiliary Supply

Each Generating Unit shall have the facility to provide its auxiliary supply during normal operation. Each Generator shall provide the facility to connect to the System for an incoming station service supply from the Single Buyer.

c. Automatic frequency response

It is required that dispatchable Generating Units have continuously fast acting response automatic governor and excitation control systems to control the Generating Unit's power output and voltage levels without instability of operation within the operating range of the unit.

d. Governor response Capability

The droop characteristics from no load to full load for Generating Units shall be adjustable in the range of (0 - 5%).

e. Black Start Capability and Dead Bus Control

Some Generating Units shall be designated to have Black Start Capability primarily considering their type and location on the system. This shall enable Generators to restart their facilities without incoming supply from the System, connect to a Dead Bus, and supply load as necessary; once on line Generators are required to be in frequency sensitive mode so as to vary with load changes. In the event of the Generator "black starting" the System, the Generator may act, temporarily upon the provision of instructions from the System Operator.

The specification of the Black Start Generating Unit shall be a subject of the Interconnection Agreement (normally contained in the PPA as a Schedule) between the System Operator and the Generator.

Where a Generator has a facility with a capacity of 60MW (excluding intermittent renewables with high and rapid variability) or greater, at least one source of Black Start supply shall be located at the site. Black Start facilities shall be routinely tested by the Generator to ensure satisfactory operation. The System Operator shall have the right to require the Generator to demonstrate the performance of the Black Start Capability. At a minimum, the Generator is required to provide a formal report to the System Operator twice a year, detailing the results of the Black Start generator test. One of these reports must be based on a test done in May of that year and shall be submitted to the System Operator before June 1 (the official start of the hurricane season). A failed event shall automatically trigger the reporting of that black start test event by the relevant Generator to the System Operator. A further report is also to be immediately submitted by the Generator to the System Operator upon subsequent successful maintenance and operation of said black start generator.

f. Fuel Supply Capability (Thermal Plants only)

The Generator shall at its own expense construct and maintain fuel supply infrastructure sufficient to store at least eighteen (18) days of fuel requirement at normal rated output subject to the provisions section GC 7 of this Code.

GC 2.2.4 Protection Requirements

a. Protective systems shall be provided in accordance with the Technical Standards set out in sub-section GC 2.2.1 and Prudent Utility Practice as generally accepted in the power industry.

b. All protective relaying equipment shall comply with the appropriate Technical Standards. At a minimum, the following protection schemes shall be provided subject to the exigencies of the relevant generation technology including inter alia;

AC generators (Reference is made to IEEE Guidelines 37.102.2006)

a. loss of Excitation (Under-reactance type);

b. differential current protection (for generator phase-to-phase fault);

c. negative phase sequence protection (for unbalanced load operation);

d. stator ground fault protection (for generator phase-to-ground faults);

e. reverse power protection;

f. Backup protection in the event of circuit breaker failure to operate;

g. Over- and under-frequency

h. over- and under-voltage

i. Thermal over-load

j. rotor (or field) ground fault protection

Transformers (Reference is made to IEEE Guidelines 37.91.2000)

a. differential current protection for generator step-up transformers

b. HV/LV phase and ground overcurrent protection (for station service/unit auxiliary transformers)

c. Buchholz and/or Sudden pressure (gas relay)

d. over excitation protection (for generator step-up transformers)

e. Backup protection in the event of circuit breaker failure to operate for generator step-up transformers

f. over-temperature protection (winding and oil)

Interconnection

a. differential (line current high-impedance) for Phase and earth faults.

b. Backup interconnection protection in the event that external phase and earth faults are not cleared by remote protection system.

c. Backup protection in the event of circuit breaker failure to operate.

   i. The protection requirements for the HV interconnection with System will depend on the interconnection voltage and the Substation configuration. The detailed arrangements for each Generating Facility are set out in the respective Interconnection Agreement. In all cases it should be ensured that each Generating Unit or Facility can be separated from the System as rapidly as possible in the event of a sustained electrical fault on either side of the Interconnection Point. The speed of separation shall be determined by the Interconnection Criteria.

   ii. The protective relaying systems shall provide the levels of sensitivity, speed and reliability as required by the System Operator. The operation of all protection schemes shall be coordinated with the operation of the System Operator's equipment.

   iii. The Generator shall submit the following design data for prior approval by the System Operator:

d. Protection and Metering single line diagrams;

e. tripping logic diagrams;

f. AC and DC schematic diagrams for the interconnection and Generating Unit protection schemes;

g. setting calculations and setting lists for the interconnection and Generating Unit protection schemes including opening/closing time for major circuit breakers; and

h. rating and transfer function data as required for computer simulation of the Generating Unit(s). This shall include data on the generator(s), transformer(s), automatic voltage regulator(s) and prime mover governor.

i. substation Equipment single line diagram.

GC 2.2.5 Variable Renewable Power Plant Interconnection Conditions

Automatic Voltage Regulation (AVR) & Fast Voltage Control.

VRPP must be capable of operating in a voltage control mode to maintain the voltage at the Point of Interconnection to stay at a set point provided by System Operator to the VRPP. The voltage setting requirement shall be within the normal operating range of the system (±5% and ±10% of nominal voltage under normal and contingency conditions respectively), with the Dead Band not exceeding 0.5%. VRPPs must respond to a sudden voltage decrease/increase with the corresponding fast positive sequence fundamental frequency reactive current output controllers. However, to fulfil these requirements at the Point of Interconnection the appropriate system studies must be carried out by the VRPP operator. VRPP System Connected Transformer Configuration.

VRPP System Connected Transformer Configuration.

VRPPs shall provide with on-load tap-changing (OLTC) facilities for its System connected power transformer. The transformer configuration and tap changing steps shall be proposed and pre- approved by the System Operator.

Voltage Flicker

Voltage Flicker is the rapid change in voltage that distorts or interferes with the normal sinusoidal voltage waveform of the Transmission System. VRPPs are not allowed to introduce significant Voltage Flicker on the Transmission Network as measured at the Point of Interconnection. The VRPP facility must not create objectionable flicker for other customers on the Licensee System. The voltage dip at the Point of Interconnection should not be more than 5% on connecting the single largest generation unit in the facility and should remain within 10% of nominal voltage when the entire facility trips. The VRPP Owner shall take steps to make sure that flicker requirements are met; there may be the need to add loss of synchronism protection, stagger generator energization, etc.

In setting and analyzing voltage flicker limits, the appropriate standards should be applied.

VRPP Harmonic Distortion.

Harmonics are waveforms that distort the fundamental 50 Hz wave. The electrical output of the customer's generating facility shall not contain harmonic content which may cause disturbances (unacceptable voltage distortion) on or damage to Licensee' electrical system, or other customer's systems, such as but not limited to computer, telephone, communication and other sensitive electronic or control systems. The VRPP facility shall follow the requirements of internationally accepted standards such as the IEEE and IEC.

GC 2.2.6 Energy Storage Interconnection Requirements (Reserved)

GC 2.3 System Operator Performance and Technical Standards

GC 2.3.1 System Frequency

The normal operating frequency of the System shall be controlled by the System Operator to be within 50.0 Hz ± 0.2 Hz.

For the avoidance of doubt, Generators including Variable Renewable Resource Power Plants shall be designed for sustained operation within the frequency limits as specified in sub-section GC 2.2.2 (a) and for restricted time based operation within the emergency frequency limits as specified in sub-section GC 2.2.2 (b).

GC 2.3.2 Generator Frequency Requirements

Generators must refer to the Generation code sub-section GC 2.3.1 for requirements for frequency support.

Under extreme system fault conditions all Generating Units must be disconnected at a frequency greater than 52.5 Hz. At a frequency less than 48.0 Hz the Generating Unit may be disconnected. Where under and over frequency relays are installed, these relays shall be set such as to facilitate the automatic removal of the Generating Unit(s) from the Transmission System. The System Operator however may specify slightly different tripping points for the various Generating Unit in order to avoid having all Generating Units on the Transmission System trip at the same time in a frequency constraint.

Generating Units must remain connected to the Transmission System during rate of change of Transmission System frequency of values at least up to and including 0.5 Hz per second.

a. No additional Generating Unit shall be synchronized while the Transmission System frequency is above 50.2 Hz.

b. The operational characteristics of the relay operation must be coordinated with other control systems of the Generating Unit (such as excitation, frequency (speed) governor response, and other controls where applicable).

c. The Generating Units at a Distributed Generation Facility must operate at a nominal frequency of 50 Hz (±0.2Hz). For frequencies considered out of this range the Generating Unit is required to trip off the Generator Governor – Primary frequency response (PFR)

Generating Units that have capacity available to either increase output or decrease output in real-time must provide PFR, which may make use of that available capacity response to System frequency deviations. The PFR shall be similar to the droop characteristic of the governor system used by conventional steam generators. The governor droop shall be set by System operator and be in the range of 0% to 5%, with a default of 5%.

The Generator resource automatic control system design shall have an adjustable dead band that defaults at +/- 0.03 Hz. This dead band means that until frequency error is beyond a threshold, the governor ignores it. When frequency error exceeds the threshold (0.03 Hz) the governor becomes active.

In Primary frequency response mode, the PFR control system shall have the capabilities as displayed in the Power-frequency response Curve in Figure GC 2.3.1 where the power and frequency ranges required for points A, B, C, D, and E shall be defined by System Operator.

All Generators in operation must reduce their instantaneous active power output when the system frequency is more than 52.5 Hz as shown in Figure GC 2.3.1 Points A, B, C, D and E in Figure GC 2.3.1 depend on a combination of the Transmission System frequency, Active Power and Active Power Control Set-point settings, and may be different for each Generator depending on system conditions and Generator location. Points A, B, C, D and E therefore may be adjusted by System Operator to accommodate requirements for system reliability which will be communicated to and agreed upon with the Generator on a case by case basis. In this figure the only defined power output point is maximum available power (100%) of the Generator; the Active Power Set Point could be in any value between 100% and down to 10%. The Active Power Set Point shall correspond to System Operator's operator designation of this value.

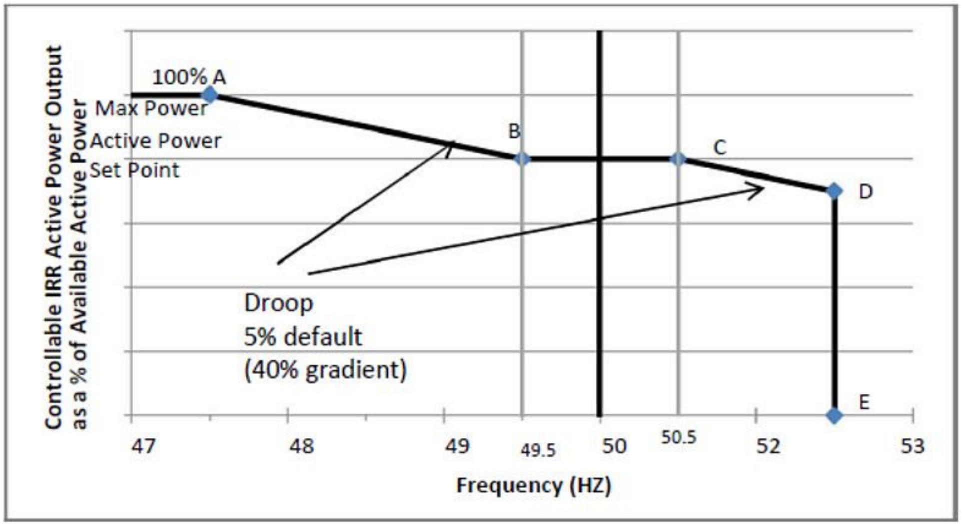


Figure GC 2.3.1 – Power-frequency response Curve

GC 2.3.3 System Voltage

The nominal operating voltages on the System shall be;

a. 138 kV and 69 kV on the transmission System; and

b. 24 kV, 13.8 kV, 12 kV, 6.9 kV, 4 kV on the Distribution System.

The normal Operating voltages shall be within:

± 5 % at the Generator Bus;

± 5 % on the Transmission System;

The contingency (abnormal) operating voltages shall be within:

± 5 at the Generator Bus;

± 10 % on the Transmission System

GC 2.3.4 Low Voltage Ride Through (LVRT)

The Low Voltage Ride-Through (LVRT) specifies the capability range for Generators to remain connected to the system during and following System faults, including the requirement to participate in the dynamic voltage control. Figure GC-S1 in Schedule F gives the Low Voltage Ride Through capability for Generators. A detail description of the operating limits are given in Schedule F of the Code.

GC 2.3.5 High Voltage Ride Through (HVRT)

Figure GC S2 refers to the positive sequence voltage at the nominal frequency. Exceeding the solid border line triggers the immediate disconnection of the unit. Generators must be capable of remaining connected at or below this limit during and immediately after any system condition. Any other disturbances as well should not result in the border line shown in Figure GC-S2 in Schedule G being crossed. These are minimum requirements; however System Operator requires equipment that is capable of riding through higher voltage and longer duration to deploy their full capability in coordination with the System Operator.

GC 2.3.6 Short Circuit Levels

The system shall be designed to withstand both symmetrical and asymmetrical short circuit conditions at the Generating Unit Substation for fault levels as specified in the appropriate Technical Standards as set out in sub-section GC 2.2.1.

GC 2.4 Other Rights Vested With the System Operator

GC 2.4.1 Inspection of Generating Plant by System Operator

The System Operator retains the right to inspect any aspect of the Generator's plant in so far as that plant is pertinent to the provision of capacity and/ or energy to the System, or to the safe and secure operation of the System, in order to verify the correct operation of all equipment including controls, circuit breakers, relays (and relay settings), metering and telemetering. Prior to exercising its right to inspect the Generator's facilities and Metering System, the System Operator shall give the Generator two (2) working days' notice and provide reasons for the inspection.

The Generator shall keep records to provide verification of tests and maintenance in accordance with agreements between the System Operator and Generator.

GC 2.4.2 Disconnection of Generator by the System Operator

The System Operator retains the right to disconnect any Generating Facility from the System thereby isolating equipment, without prior notice under the following circumstances:

a. in cases of System Emergency;

b. during system restoration following partial or complete loss of power;

c. if at any time the Generating Facility is being operated outside acceptable operating parameters in a manner which violates the Interconnection Conditions set out in the Code or which is likely to cause any of the following:

   i. A safety risk to personnel;

ii. Risk to stability or security of the System or Other Generating Units;

iii. Any behavior causing sustained operation outside the normal System operating frequency and voltages as stated under sub-section GC 2.3

Notwithstanding the forgoing in the event of any material breach of Interconnection Conditions which prevents the System Operator from meeting its Licence obligations, the System Operator may disconnect after using best commercial efforts to give notice to the Generator.

GC 3 OPERATIONAL METERING

Adequate Metering Systems consistent with the technical specifications of this Generation Code shall be installed by the Generator. The Metering System shall comprise a Primary and Backup Metering System and shall be designed, financed and installed by the Generator. The System Operator shall own and maintain the Primary Metering System while the Generator shall own and maintain the Backup Metering System.

GC 3.1 Technical Standards for Operational Metering

GC 3.1.1 Location of Metering Equipment

a. Both Primary and Backup Metering Systems shall be installed to accumulate the outputs and/or inputs at the High Voltage side of the generator step-up transformer.

b. Each meter shall have its own current transformer (CT) and potential transformers (PT) and necessary independent systems to function effectively.

c. For Generators less than 100 kW, metering requirements of the Standard Offer Contract in addition to the provisions of sub-section GC 3.2.4 of this Code shall apply. Refer to “Jamaica Public Service Company Limited Standard Offer Contract for the Purchase of As-Available Energy from intermittent Renewable Energy Facilities up to 100 Kw”.

GC 3.1.2 Metering Standards

a. Instrument transformers shall conform to ANSI Standards C12.11 and C57.14 Class 03 and shall have sufficient capacity to supply the burden produced by the wiring and metering equipment.

b. The current transformers secondary winding used for metering purposes shall supply only the metering equipment and associated systems.

Notwithstanding the foregoing each current transformer may have other secondary windings that may be used for purposes other than metering.

c. Potential transformers' secondary windings may be used for metering and other purposes provided that the total loading does not exceed one half the rating of the transformer.

d. Any metering and accumulating equipment shall have sufficient accuracy so that any error resulting from such equipment shall not exceed ±0.5% of full scale ("Allowable Error").

GC 3.1.3 Sealing, Field testing and Inspection of Metering Systems

Meters and associated instrument transformer boxes or enclosures shall be sealed by and at the expense of the Generators at the respective meters. The type of seal shall be approved by the System Operator.

For wiring used only for metering purposes, solid metallic conduit runs shall be used to enclose the wiring connecting the instrument transformers and the related accumulating and metering equipment. Any boxes or enclosures or other devices used to join two or more sections of conduit shall be securely covered, fastened and sealed with seals approved by the System Operator.

If the wiring used for metering must pass through a panel, panel board or switchgear structure, it shall be fastened together and cabled as a unit separate and apart from the rest of the wiring.

At its own expense, the Generator shall provide any terminal blocks that may be used along the length of the metering conductors within a panel, panel board or switchgear with covers or strips that limit access to the respective connections and said covers or strips shall be affixed with a seal approved by the System Operator. Boxes or enclosures shall be sealed with pre-numbered seals approved by the System Operator.

Seals shall not be broken by anyone except the System Operator's personnel when the meters are to be inspected, tested or adjusted. The System Operator shall notify the Generator in advance of such inspection, testing or adjustment, and the Generator has the right to have a representative present.

Before the commissioning of any Generating Unit, the System Operator shall test the Metering System for correct wiring and accuracy, using equipment whose accuracy is equal to or better than that of the individual meters. Individual meter components found to be inaccurate before commissioning shall be returned to the Generator for replacement. Malfunctions identified after full acceptance of the Metering System shall be the responsibility of the individual owners.

The System Operator shall test the Metering System within ten (10) days after:

a. the detection of a difference larger than the Allowable Error in the readings of the meters;

b. the repair of all or part of a meter caused by the failure of one or more parts to operate in accordance with the specifications; and/or

c. each anniversary of the commissioning date of the unit. If any errors in the readings of the meters are discovered by such testing, the Party owning those meters shall repair, recalibrate or replace those meters and shall give the other Party reasonable advance notice so that the Party receiving notice may have a representative present during any such corrective activity.

GC 3.2 Meter Reading Procedures

GC 3.2.1 Parameters for Meter Reading

The Generator shall provide and install appropriate equipment and shall make continuous recordings on appropriate magnetic media or equivalent of the Net Energy Output and Dependable Capacity if applicable, of the Generating Unit(s).

The parameters to be metered shall be subjected to the Interconnection Agreement between the Generator and the System Operator, and may consist of but not limited to any or all of the following parameters:

a. Active energy (MWh) OUT;

b. Active energy (MWh) IN;

c. Reactive energy (MVARh) First Quadrant;

d. Reactive energy (MVARh) Fourth Quadrant;

e. Active Power Demand (MW) OUT;

f. Active Power Demand (MW) IN;

g. Reactive Power Demand (MVAR) First Quadrant; and

h. Reactive Power Demand (MVAR) Fourth Quadrant.

GC 3.2.2 Frequency of Reading

The Demand interval shall be (15) minutes and shall be set to start at the beginning of the hour. Demand shall be calculated by averaging the respective over the stated Demand Interval.

The System Operator shall read the appropriate meters to prevent clock drift. The clocks shall be checked and reset as agreed by the Parties. If readings are obtained remotely, copies of the data produced by the computer which initiates the reading protocol can be made and provided to the Generator if requested.

GC 3.2.3 Control Procedures

The System Operator shall inform the Generator at least 24 hours prior to reading the meters and the Generator shall have the right to have a representative to witness such readings.

For the Demand actually experienced throughout the billing period, the meters shall be equipped with a mass memory module of a minimum of 3 months which shall record the parameters in sub-section GC 3.2.1.

GC 3.2.4 Metering Requirements for Generators <100 kW

For small Generating Facilities with rated capacity below 100 kW the full metering requirements in sub-section 3.1 may be reduced. These Facilities will be permitted to be metered using separate import and export meters. The terms and conditions of this arrangement shall be guided by the Standard Offer Contract (SOC).

The metering equipment shall be a bi-directional device or a smart meter having the capability of mass memory, remote reading and power quality monitoring. Specification of the meter shall be provided by the System Operator and the Qualifying Entity shall purchase the metering equipment which shall be owned and maintained by the Single Buyer.

GC 3.3 Reconciliation Procedures

If the Primary Metering System is known to be inaccurate or otherwise functioning improperly, then the Backup Metering System shall be used during the period that the Primary Metering System is not in service and the provisions described in sub-section 3.2 shall apply to the reading for the Backup Metering System.

If the Primary Metering System is found to be inaccurate by more than the Allowable Error or to otherwise have functioned improperly during the previous Month, then the correct amount of Net Energy Output and Dependable Capacity for the actual period during which inaccurate measurements, if any, were made shall be determined as follows:

a. First, the reading of the Backup Metering System shall be utilized to calculate the correct amount of Net Energy Output and Dependable Capacity, unless a test of such Backup Metering System, as required by either Party, reveals that the Backup Metering System is inaccurate by more than the Allowable Error or is otherwise functioning improperly;

b. and If the Backup Metering System is not within the acceptable limits of accuracy or is otherwise functioning improperly, then the Generator and the System Operator shall jointly prepare a reasonable estimate of the correct reading on the basis of all available information and such guidelines as may have been previously agreed to between the Generator and the System Operator. This estimate shall take into account but not be limited to Dispatch Instructions as recorded in the System Control Centre dispatch log and meter readings, remote or manual.

GC 3.4 Resolution of Disputes over Recorded Metering Data

If the System Operator and the Generator fail to agree upon an estimate for the correct reading within a reasonable time (as specified in the relevant PPA) of the Dispute being raised, then the matter may be referred for arbitration by either Party in accordance with the relevant PPA.

GC 4 MERIT ORDER SYSTEM

The System Operator shall establish a Merit Order based on the real or contracted Variable Operating Cost component of each Generating Unit or Complex, whichever is applicable.

The Variable Cost of each Generating Unit or Complex is the sum of the Variable Operating & Maintenance Cost (VOM) and the Fuel Cost. In mathematical form:

Merit Order Cost (\$/MWh) = Fuel Cost (\$/MBTU) x Full Load Heat Rate (MBTU/MWh) + VOM (\$/MWh)

This information allows the System Operator to rank the Generating Units in the order of their Full Load Point cost of operation.

Refer to section DSC 5 of the Dispatch Code for details of the Merit Order System.

GC 5 SCADA INTERFACING

This section sets out the technical requirements for connections to the Operator's Supervisory Control and Data Acquisition (SCADA) system outstation in terms of electrical characteristics.

GC 5.1 General Requirements

In all cases signals shall be arranged such that the level of electrical interference does not exceed those defined in IEC 870-2-1: "Telecontrol Equipment and Systems - Operating Conditions - Power Supply and Electromagnetic Compatibility" and IEC870-3: "Telecontrol Equipment and Systems - Specification for Interfaces (Electrical Characteristics)".

Digital Inputs

Digital inputs cover both single and double points for interconnection to digital input modules on the System Operators outstation equipment. The Equipment contacts shall be free of potential, whereas the input circuitry of the outstation are common to the negative 48 volt potential.

Single Points

Single point inputs must be used for alarms and where single contact indications are available. The off (contact open or 0) state is considered to be the normal state and the on (contact closed or 1) state the alarm condition.

Double Points

Double points are used to indicate primary plant states by the use of complementary inputs for each plant item. Only the "10" and "01" states are considered valid with the "00" and "11" states considered invalid. The "10" state is considered to be the normal or closed state.

Energy Meter Inputs

Energy meter input pulses for interconnection to pulse counting input modules on the System Operator's outstation equipment must operate for a minimum of 100ms to indicate a predetermined flow of MWh or MVArh. The contact must open again for a minimum of 100ms. The normal state of the input must be open.

Analogue Inputs

Analogue inputs for interconnection to analogue input modules on the System Operator's outstation equipment must all be electrically isolated with a two wire interconnection required. Signals shall be in the form of 4-20mA (or other range to be agreed between the User and the System Operator) for both unidirectional and bi-directional measured values. Signal converters shall be provided as necessary to produce the correct input signals.

Command Outputs

All command outputs for interconnection to command output modules on the System Operator's outstation equipment switch both the 0 volts and -48 volts for a period of 2.5 seconds at a maximum current of 1 amp. All outputs shall be electrically isolated with a two wire interconnection to control interposing relays on the plant to be operated.

GC 6 COMMUNICATION AND REPORTING

The Generator is required to provide information as requested, pertaining to the operation of their Generating Unit(s).

GC 6.1 Designated Contact Persons

The System Operator shall at all times have a person designated as the System Control Engineer.

Each Generator shall at all times have a person designated as the Generating Unit Controller in charge of operation and control of each Generating Unit.

GC 6.2 System Control Centre Record of Dispatch

A record of events shall be kept at the System Control Centre, which shall include, but not be limited to:

a. all instructions regarding switching, voltage control and Generating Unit operation;

b. deviations in frequency outside the normal range;

c. each operation or sequence of operations of circuit breakers, disconnectors and earthing switches under the control of the System Control Engineer and, where appropriate, alarms and protection indications; Transformer tap changers instructed or operated by the System Control Engineer;

d. the synchronization or taking off-line of Generating Units;

e. details of the application and removal of all h short and grounds and other safety precautions, including the issue and cancellation of safety documents and HV live line working certificates, by the System Control

Engineer or his designate as required by the System Operator's safety rules;

f. the commissioning, taking out of service or re-commissioning of plant and apparatus, including automatic switching systems, protection and changes to relay settings, together with relevant details;

g. the failure, or change of state, of plant or apparatus on the System together with relevant details;

h. the failure of plant or apparatus affecting the availability of Generating Unit(s), together with relevant details;

i. the location and identification of switchgear for which a risk of trip is expected;

j. Generating Units which are not operating in the frequency sensitive mode;

k. any significant abnormal or dangerous occurrence in operation including incidents involving the use of emergency public service;

l. any interruption and restoration of supply together with relevant details;

m. details of the System Operator System load reductions, restorations and Demand control;

n. System/ standard time deviation at 7:30 a.m. Eastern Standard Time and 9:30 p.m. Eastern Standard Time or as may be required.

GC 6.3 Generator Operations Log

The Generator shall maintain an accurate and up-to-date Operations Log. The purpose of this Operations Log is to record significant events, plans, requests and instructions. Entries into the Operations Log should be made on a daily basis and should include, as necessary, the following:

a. Dispatching Instructions and times of receipt of such instructions from the System Control Engineer;

b. Time of implementation of instructions;

c. Any request from the Generator to the System Control Engineer which includes:

   i. Scheduled outages;

   ii. Forced outages;

   iii. Load adjustments;

   iv. Maintenance Outages;

   v. Emergencies of any kind affecting the operation of the Generating Facility and Daily available Capacity.

   vi. Names and status of all personnel on each shift;

   vii. Daily midnight readings of the fuel used and in stock;

d. Statements relating to abnormal running conditions of Generating Unit(s) and auxiliaries;

e. All Real (kW) and Reactive (KVAR) Power at half hour intervals, frequency and voltage, at the 69 kV bus bar and 138 kV bus bar at half hour intervals, unit auxiliary and station bus bar voltage and real and reactive power; any units connected at the distribution level should record similar information at the connected bus bar.

f. Generating Facilities operating on an energy-only basis with installed capacity below 15MW may not be manned at all hours and hence may not record these parameters immediately at every half hour. For these types of Generators, adequate SCADA infrastructure shall be put in place by the Generator for remote monitoring of said parameters by the Generator and System Operator, as well as local real time data capture and storage of the above parameters by the Generator.

g. Time of trip-out or removal of Generating Units from service and the time of return to service; and Visits by factory inspectors to the Generating Facility.

GC 7 FUEL SUPPLY AGREEMENT

The Fuel Supply Agreement shall at a minimum:

a. demonstrate a dependable and sufficient fuel supply;

b. detail the infrastructure installed for delivery of the fuel from the central storage point to the plant gate;

c. provide mitigating strategies in the event of natural disaster affecting the supply of fuel delivery to Jamaica;

d. detail Fuel Transportation Agreement; and

e. detail alternative fuel supply arrangements and infrastructure requirements.

All Generators shall be required to:

a. obtain and maintain reliable supply of fuel (on-site storage exclusive to the Generating Facility) of quality and quantity sufficient to generate the Dependable Capacity and the Net Energy Output requirements of their Generating Facilities for a period of at least eighteen (18) days and the minimum inventory level should be 7-10 days. Note that the System Operator must canvas the Generators to obtain the inventory levels and advise the Generator to evaluate available options if the levels are below required levels or trending negatively for uninterrupted operations. The System Operator shall seek permission via an application to the OUR to trigger an emergency plan.

b. provide the System Operator the Fuel Supply Plan; as duly approved by the OUR, in consultation with the System Operator.

c. only enter into fuel supply arrangements consistent with the Fuel Supply Plan.

d. any Renewable Fuel Feed Stock that a Renewable Energy Generating Plant uses in the conversion process to ultimately generate electricity must be derived from indigenous source(s).

GC 8 GENERATOR SCHEDULING & DISPATCHING TOOLS

The System Operator is required to ensure consistency and objectivity in the decision-making mechanisms used. These mechanisms may be in the form of standardized procedures and/or computational systems.

The System Operator is responsible for updating the System Control Policy & Procedures as required, due to changes in the system characteristics or international best practices, where it has relevance to the Jamaican Electric Power System. Documentation of the procedures followed in making System operations decisions must be promulgated to individual Generators after ratification by the OUR.

The tools used to assist in the Generator Scheduling and Dispatch optimization process must be based on an internationally accepted optimization algorithm. The tools must be used in accordance with its intended design and the System Operator is responsible for ensuring that it is functional and accurate.

GC 8.1 Non-Centrally Dispatched Plant

Non-centrally Dispatchable Generating Units shall operate as agreed upon between the System Operator and the Generator. The System Operator shall inform such Generators where there is a need for outage on the Generating Unit or of any incident which would affect the operations or safety of the Generating Unit. During an Emergency, or where there is life and property at risk, the System Operator and/or the Generator reserves the right to disconnect and so isolate any Generating Unit without prior notification. However, both Parties must communicate immediately but in no case more than six(6) hours of the neutralization of the risk , to inform of the action taken and why it was necessary to take such action without prior notice.

The Generator shall communicate with the System Control Engineer on matters of switching and Synchronization during normal operations and in the event of System Emergency.

GC 8.2 Generation Forecast and Dispatch

All Generators shall cooperate with System Control Centre by providing generation forecasts that System Operator shall use to schedule the demand energy and dispatch the necessary units to operate the system reliably.

GC 8.3 Variable Resource Forecasting

System Operator requires the VRPP to provide quality resource forecast from reputable and industry proven methods, and or in accordance with requirements that will be dictated by System Operator in a Power Purchase Agreement or other Agreement between System Operator and the VRPP. The forecast should provide the following information:

GC 8.3.1 Medium-Term Forecast

A rolling half hourly resource forecast submitted to System Operator for the next 168 hours. The rolling half hourly forecast means the forecast must be provided on an half hourly basis.

GC 8.3.2 Short-Term Forecast

System Operator reserves the right to also request a rolling 5-minute resource forecast to be submitted to System Operator and/or the centralized forecasting vendor for the next 6 hours.

The System Operator is required to consolidate forecasting functions in a single provider to assure uniformity of quality and improved forecasting prediction capacity, and to share the costs among the users.

The forecasts shall be provided to the System Operator through web service or ftp (File Transfer Protocol) site delivery in a format to be agreed upon with the System Operator. The System Operator reserves the right to request a specific file format that the VRPP must accommodate.

GC 8.4 Transparency and Fairness

In order to assure transparency and fairness while being cognizant of the confidentiality provisions in individual contracts, the following outlines how and what type of information will be shared among stakeholders in the generation market. Unless explicitly stated otherwise in the document, the following shall prevail:

a. The Regulator: The OUR shall be allowed access to any and all available information it requires from both the individual Generators or Complex, and the System Operator. Periodically as agreed between the System Operator and the OUR, Technical Reports will be compiled by the System Operator and provided to the OUR, and will contain information from the logged system parameters as agreed from time to time.

b. Individual Generator: The System Operator is required to provide, in a timely manner, individual Generators with any technical system information that affects the operation of interconnected Generating Units for example, fault information should be shared with all Generators, with due consideration of the specific confidentiality provisions contained in each PPA and Licence.

c. System Operator: The System Operator shall have timely access to all information it reasonably requires from the individual Generators.

GC 9 NEW TECHNOLOGIES

New generation technologies that have parameters not covered by this Code may be given consideration for inclusion to the System. However, the OUR, in full consultation with the System Operator, shall first provide written approval of the technical compatibility of the technology with the System, before the new technology can be interconnected. Accordingly and as necessary, as soon as possible thereafter, the respective Code (s) should be updated using the Code Review Process and necessary amendments made to the Book of Codes.

GC 10 GENERATOR MAINTENANCE PLANNING

GC 10.1 Long Term Maintenance

GC 10.1.1 Planning Horizon

The System Operator shall develop an overall generation maintenance plan for three (3) years in advance. The first year shall be sufficiently detailed with less detail for the following years 2 and 3. The plan which shall incorporate statutory maintenance requirements shall be reviewed annually and updated as may be necessary.

To achieve this objective, Generators shall submit to the System Operator on or before the first day of July of each year a rolling three year plan for the scheduled maintenance requirement for their facility beginning in January of the following year. The System Operator shall submit the finalized, overall generation maintenance plan to the OUR by January 1 of each year and each Generator shall submit its final generation maintenance plan to the OUR by January 1 of each year.

The System Operator shall schedule both long and short term Maintenance Outages in a non-discriminatory manner as far as System security constraints reasonably allow. Both System Operator and Generator shall ensure that interconnection and other related facilities are maintained within the periods stipulated for scheduled maintenance of the Generating Facility, given the relevant technical constraints.

GC 10.1.2 Annual Commitment of Maintenance Program

Generators shall submit to System Operator on or before the first day of July of each Year, a schedule (the 'Maintenance Schedule') describing the proposed availability of the Generating Facility for each Month of the twelve (12) Month period beginning with January of the following Year. The Maintenance Schedule shall indicate the Generators' preferred dates and durations of all scheduled maintenance. In developing the plan the System Operator shall take into account the manufactures recommendations for maintenance of the plant.

The System Operator shall notify Generators in writing whether the scheduled maintenance periods requested on the Maintenance Schedule are acceptable. The System Operator shall have the right to request the Generators to conduct scheduled maintenance during periods other than those indicated in the Maintenance Schedule, provided that the period specified by the System Operator shall be as close as reasonably practicable to the periods requested by the Generators, shall be of equal duration as the periods requested by the Generator and shall be within the range of time periods identified by the Generator as the range of time periods within which such scheduled maintenance must be performed in accordance with the manufacturer's recommendations for the Generating Facility.

GC 10.1.3 Changes to the Committed Maintenance Schedules

Committed Generating Unit Maintenance Schedules shall be strictly adhered to unless unanticipated circumstances may mean interruption of supply to customers or a compromise in System security if the Maintenance Schedule is not adjusted. Under such circumstances both the System Operator and the Generator shall make best efforts to reschedule the outage as follows:

a. System Operator may upon five (5) days prior notice request Generator to reschedule a scheduled maintenance provided, however, that System Operator shall not request that scheduled maintenance be rescheduled to a time that is outside of the range of time periods identified by the Generator as the range of time periods within which such scheduled maintenance must be performed in accordance with the manufacturers recommendations for the Generating Facility;

b. Generator may, upon five (5) days prior written notice, request that it be permitted to conduct additional scheduled maintenance for a period not identified in the Maintenance Schedule if the maintenance to be conducted cannot be postponed until the next period of scheduled maintenance identified on the Maintenance Schedules without damaging or otherwise threatening the Generating Facilities. Generator's request shall also identify the range of time periods within which such additional scheduled maintenance shall be performed in order to avoid damaging or otherwise threatening the Generating Facilities. System Operator may upon three days prior written notice, request Generator to reschedule such additional scheduled maintenance; provided, however, that System Operator shall not request that such additional scheduled maintenance be rescheduled to a time that is outside of the time periods identified by the Generator as the range of time period within which such additional scheduled maintenance shall be performed in order to avoid damaging or otherwise threatening the Generating Facilities.

c. if the Generating Facility is inside a scheduled maintenance period and requires an extension of the maintenance period, the System Operator shall have the right to review and determine if the extension can be accommodated or the extended work period is to be classified as Forced Outage.

GC 10.2 Short term Outage Program

For short term outages Generators shall give the System Operator at least two (2) hours' notice prior to taking the Generating Facilities out of service.

The granting of such outages shall be at the sole discretion of the System Operator.

GC 11 SCHEDULES OF RESPONSIBILITY

GC 11.1 Ownership, Operation and Maintenance Schedules

Schedules specifying the ownership and the responsibilities for Operation an Maintenance shall be jointly agreed by the System Operator and the appropriate Generator for each location where either an Operational Interface or joint responsibilities exist. For those Generators connected at MV and having firm supply connections provided by more than one circuit, and where the Generator so requests the System Operator, these schedules shall identify those specified System Operator circuits for Planned Outages and the Generator shall be notified at least two(2) weeks in advance of the planned outage.

These specified circuits shall usually operate at the voltage level at which the supply is provided and shall have a significant effect on the security level of the Generator's s supply. These specified circuits shall be those where the System Operator and the Generator have agreed that during the outages of the specified circuits the Generator can introduce measures to manage critical processes or safety aspects. Those Generators connected at MV and not having firm interconnections provided by more than one circuit may seek to obtain outage planning information through established arrangements with the System Operator.

GC 11.2 Maintenance of Schedules and Diagrams

All schedules and diagrams shall be maintained by the System Operator and appropriate Generator and exchanged as necessary to ensure they reflect the current agreements and network configuration.

GC 12 TESTING AND MONITORING

GC 12.1 Procedures for Conducting Tests

The Generator shall provide to the System Operator a timetable and a list of all tests to be performed on the Generating Units, and such tests shall be subject to approval by the System Operator. The System Operator shall be given five (5) days' notice of any testing and shall reserve the right to have a representative present during any such tests.

GC 12.2 Standard Tests

This section addresses procedures for testing and monitoring of Generating Units for purposes of determining available Capacity and, if relevant, operating characteristics in accordance with the commercial and technical conditions of Power Purchase Agreements. An Independent Engineer shall be required for the commissioning of new Generating Facilities.

GC 12.2.1 Test Prior to First Synchronization

a. Mandatory Tests that may be carried out at the Factory prior to Equipment delivery at the Site of the New Generator Facility.

   i. prime mover governor control checks;

   ii. Automatic Voltage Regulator (AVR) setting up and adjusting with the Generating Unit running at rated load;

   iii. open and short circuit tests on the generator as per IEC 60034 or equivalent under the standard bodies of sub-section GC 2.2.1; and

   iv. Governor tests for units not allowed to perform full load rejection tests under sub-section GC 12.2.2.

   In each instance, the Generator shall provide the System Operator with the results of all such tests, within a reasonable time of the test being completed.

b. Tests that shall be completed at the Site of New Generating Facility

   i. Grounding test at the generator switchyard;

   ii. functional testing and timing of High Voltage switchgear in the Substation;

   iii. voltage phasing checks between the Substation to which the Generating Unit is connected and the System;

   iv. primary and/or secondary injection tests and functional tests to prove the calibration and function of all electrical protection schemes installed for the Generating Unit(s) and the Facility. Frequency Relaying Test to confirm that the plant relays are configured adequately and per frequency criteria sub-section GC 2.3.2 of this Generation Code Relaying Requirements. This functionality test is required to ensure that the Generating Unit will not disconnect from the System during the specified frequency range and delay to trip times provided within sub-section GC 2.3.2 of this Code.

v. There are no trend requirements for these tests. However, the necessary SCADA and Control equipment should be online and operational to be able to perform these tests as System Operator will need to confirm the position (Open/Close) of breakers during the test at the System Control Centre.

Upon completion of each test the Generator shall within forty eight (48) hours provide the System Operator with two (2) copies of the results of such tests.

The System Operator shall have the right to request additional testing if, in its judgment verified by an Independent Engineer, any test results are not satisfactory for establishing the purpose for which the test was intended. Such additional testing shall be performed at the Generator's expense.

The Generator shall confirm to the System Operator the programme for any test as specified or advise of any adjustments thereto, not less than five (5) days prior to the commencement.

GC 12.2.2 Tests after First Synchronization

After the Pre-Synchronization tests as defined in sub-section GC 12.2.1 and prior to the commencing date, and under such subsequent conditions as defined by Power Purchase Agreements, Generator shall carry out the following tests at the Generator's expense:

a. Dependable Capacity

The Generator shall test the Dependable Capacity of the Generating Unit. The test shall be performed according to ASME, IEEE, ISO, and NEMA standards or to equivalent standards of sub-section GC 2.2.1. If any such standards are inconsistent in any respect, the test shall be performed in accordance with the most stringent standard.

b. Reliability Run

The Generator shall test the Reliability of the Generating Units in accordance with industry standards based on the type of plant and established international codes for the industry.

c. Automatic Voltage Regulator (AVR) Droop

The Generator shall test the AVR to demonstrate control of the Generating Unit voltage over the range of plus or minus five (±5) percent of rated voltage with a droop characteristic of plus or minus one half (±0.5) percent.

Voltage ride through tests

The Generator shall determine whether the Generating Units are capable of detecting and riding through voltage dips without tripping and to provide the necessary support to the System in terms of active power and reactive current injection as given in sub-section GC 2.3.4 of this Code.

d. Governor Operation

The Generator shall demonstrate that the speed governor for each Generating Unit operates over its range, the droop being adjustable from two (2) percent to five (5) percent.

Primary Frequency Response (PFR) Test

The PFR Test will be carried out by the Generator to assess the ability of the Generator controller to provide frequency support to the System Operator Transmission System. The PFR Test will be carried out by the Generator to verify that the Generator is capable to either increase output or decrease output in real-time when the system frequency is outside the 50 ±0.5 Hz range. The Generator shall conduct the test based on the procedures below and show compliance with sub-section GC 2.3.3 of this Code.

e. Reactive Capacity

The Generator shall test each Generating Unit's capability to operate at rated voltage and frequency at power factors and under reactive conditions according to the technology used. Where synchronous generators are used, the minimum capabilities shall be as follows:

100% output: 0.80 lag; 0.99 lead.

f. Short-term Load Capability

The Generator shall test each Generating Unit's capability to operate at a maximum safe load of one hundred and ten percent (110%) of the Required Dependable Capacity for at least one (1) hour. Where the Generating Unit cannot undergo a “Rapid Start”, this unit must also be able to operate at a minimum safe load of at least zero (0) percent of the Dependable Capacity (0 MW) for one (1) hour.

g. Response of Unit to Step Load Changes

For prime mover technologies that allow controllable load changes, the Generator shall test the capability of each Generating Unit to increase load by steps.

h. Full Load Rejection

The Generator shall test the capability of each Generating Unit and auxiliaries to withstand 'Partial Load Rejection,' while remaining in a safe condition and without initiating a trip of the Generating Unit. Where a Generating Unit cannot undergo a Rapid Start, the Generator shall also test and prove the capability for each Generating Unit to withstand 'Full Load Rejection' while remaining in a safe condition and without initiating a trip of the Generating Unit.

Where a Co-Generator may determine that a Full Load Rejection test may cause a severe disruption of the Co-Generator's process operations, then a Partial Load Rejection test at a load value capable of being managed by its process operations shall be conducted instead.

GC 12.2.3 Thermal Performance Tests

The Generator shall test the Heat Rate of each Generating Unit.

Heat Rate is computed by dividing the total British thermal unit (Btu) content of fuel consumed for electricity generation by the resulting net kilowatt-hour generation. The Basis of the value should always be expressed as either Lower Heating Value (LHV) or Higher Heating Value (HHV). The basis of the heating value provided shall be consistent with the relevant contractual arrangements and the capability of the generation technology employed.

The Heat Rate data for each Generating Unit is necessary to determine its variable fuel operating cost. All contracts for new generating capacity shall have a guaranteed Heat Rate curve or point.

The Heat Rate Tests for each Generating Unit, not having a guaranteed curve or point, shall normally be conducted at least twice annually or as stipulated by contract. The schedules for the Heat Rate Test for all dispatchable Generating Units shall be developed by the System Operator at least one Month before the end of the preceding Year. The Heat Rate Test schedules may be adjusted within the Year to accommodate unforeseen circumstances, subject to agreement between the Generator and the System Operator. Such schedules for Heat Rate Test shall be submitted to the OUR by the System Operator.

The Heat Rate Test shall be conducted at a minimum of four (4) output levels from the minimum output level to the maximum output level for each Generating Unit.

The Heat Rate information obtained from Heat Rate Tests together with the guaranteed Heat Rates (for units to which this is applicable) shall be used as one of the inputs to the Generator Scheduling and Dispatch optimization process.

If the System Operator has sufficient reasons to believe that the Heat Rate of a Generating Unit which does not have a guaranteed curve or point, has changed significantly within the Month or since the last test (due to rehabilitation, damage etc.) the System Operator may request the Generator to conduct a Heat Rate Test in accordance with the System Operator Heat Rate Testing Policy (in the case of System Operator owned generators) or other approved policy (in the case of non-System Operator generators) and update the Heat Rate curve for such a Generating Unit. All cost associated with the Heat Rate test shall be the responsibility of the Generator.

The Generator may request a heat rate test of its own unit if it can provide information to substantiate that it has made improvements in the performance of its Unit(s). No more than two such requests will be accommodated within any calendar year.

Heat Rate Tests for all Generating Units, including those of the Single Buyer, shall be coordinated (mutually agreed date) by the System Control Engineer. The System Operator shall reserve the right to witness all such tests.

The OUR shall be advised and duly notified beforehand when such tests are contemplated and carried out and reserves the right to witness all such tests.

In the case of Independent Power Producers, the information on which the Generating Units will be ranked shall be based on the contractually agreed performance or such other criteria as established through the Power Purchase Agreement between the Generator and the Single Buyer.

The System Operator shall have the right to request additional testing if, in its judgment verified by an Independent Engineer, any test results are not satisfactory for establishing the purpose for which the test was intended. Such additional testing shall be performed at the Generator's expense. The results of the immediately prior test shall govern until the additional test is completed. The results of the additional test shall supersede the prior test for all purposes commencing on the day following the additional test.

The Generator shall notify the System Operator of the proposed programme for any test specified in this section, or advise of any adjustments thereto, not less than five (5) days prior to the proposed commencement of the relevant test. Upon receiving such notice, the System Operator shall have the right to reschedule the commencement of such test; provided that the rescheduled commencement shall not be more than three (3) days before the proposed commencement nor more than ten (10) days after the proposed commencement. The Single Buyer and the System Operator shall be entitled to have representatives present for the purpose of observing any such test. The OUR shall be notified beforehand by the Generator of all test programmes and shall have the right to have Officers present for the purpose of observing any such test.

Upon completion of each test specified in this section, The Generator shall promptly provide the System Operator with two (2) copies of the results of such test, which shall be copied to the OUR; provided that the Generator shall submit all such test results to the Single Buyer and System Operator no later than ninety (90) days after the commissioned date of the relevant Generating Unit or Facility.

GC 12.3 Co-Generators

Co-Generators Generating Units shall be required to perform all tests as listed sub-section GC 12.2.

GC 12.4 Variable Renewable Power Plant Connected to the System

VRPPs connected to either the Transmission or Distribution network, section shall be required to perform all tests as listed in sub-section GC 12.2, where applicable. In addition to the following tests listed below. Meteorological Data and respective Generation (supply) forecast which applies to photo voltaic plants and wind plants:

a. Wind Speed

b. Wind Direction

c. Air Temperature

d. Air Pressure

e. Solar Irradiance

f. Forecasted Generation (supply) schedules for periods as required.

GC 12.4.1 Maximum Reactive Power Capability Test

The purpose of this test is to confirm the ability of the VRPP to operate to the limits of the reactive power capability curve for VRPPs as indicated in Figure GC 2.2.5 of sub-section GC 2.2.5 and also to establish the limits of the VRPP reactive power capability at the High Voltage bus. The test shall be completed for both the export of reactive power from the VRPP as well as the import of reactive power to the VRPP. The point of measurement for compliance will be the VRPP Interconnection Point. This test should be undertaken at different levels of active power to confirm that the range is within the capability characteristic at the given level of power. This test will be carried out at a time when the actual MW Output of the VRPP is greater than 80% of Registered Capacity and 95% of the VRPP Generating Units are in service.

The test should be carried out to determine both:

a. the Maximum Lagging Reactive (Exporting) capability of the VRPP and

b. the Maximum Leading Reactive (importing) capability of the VRPP

GC 12.4.2 Voltage Flicker Measurements

The purpose of this test is to confirm the ability of the VRPP to operate within the limits in sub-section GC 2.2.5. Voltage Flicker during normal system operation. This test shall take place for a period of one week after all Generating Units have been individually commissioned. During the period of measurement, there shall be some period of time, if not all the time, during which 100% of the VRPP Generating Units are in service and providing active power. In carrying out the measurements the appropriate standard such as IEEE 1453 or equivalent should be applied.

GC 12.4.3 Harmonic Distortion Measurements

The purpose of this test is to confirm the ability of the VRPP to operate within the Harmonics limits specified in table GC 2.2.5 of sub-section GC 2.2.5 for normal system operation. This test shall take place for a period of 24 hours after all Generating Units have been individually commissioned and it may be run at the same period of the voltage flicker measurements. During the period of measurement, there shall be some period of time, if not all the time, during which 100% of the VRPPs are in service and providing active power.

GC 12.4.4 Testing of Metering System

These testing procedures are outlined in section GC 3 of this Code.

GC 12.5 Parameters Monitoring

For modeling of the System, Generators shall be required to periodically (5-10 years) submit the Generator operating parameters to determine if there is any decay which should be modeled.

Generators shall carryout routine and prototype response tests on excitation systems and governor systems (unit frequency response) for new power stations coming on-line or power stations at which major refurbishment or upgrades of these systems have taken place. Routine review is required of all power stations at least once every five (5) years.

GC 13 MONITORING AND CONTROL

This section outline the means and methods by which system operators and System participants will be able monitor and control individual generating plant and the power system on a whole. It sets out the responsibilities of each of the Parties, and the communication systems requirements through which the necessary information and dataset will be provided.

GC 13.1 Remote Monitoring

a. The System Operator may require the generator to, within a reasonable time of notice being given in writing:

   i. install remote monitoring equipment ("RME") adequate to enable the System Operator to remotely monitor performance of a generator (including its dynamic performance) where this is reasonably necessary in real time or with small delay for control, planning or security of the power system; and (2) upgrade, modify or replace any RME already installed in a power station provided that the existing RME is, in the reasonable opinion of the System Operator, no longer fit for the intended purpose.

b. Input Information to RME may include, (without limitation) the following:

   i. Status Indications

      - generator circuit breaker open/closed;
      - remote generator control on/off;
      - remote generator control high limit reached;
      - remote generator control low limit reached; andgenerator operating mode;

   ii. Alarms

      - generator circuit breaker tripped by protection;
      - urgent and non-urgent alarms
      - measured Values
      - Generating Unit active power;
      - Generating Unit reactive power;
      - Generating Unit stator/terminal voltage;
      - Generating Unit remote generation control high limit value;
      - Generating Unit remote generation control low limit value;
      - and Generating Unit remote generation control rate limit value.

Such other input information reasonably required by the System Operator.

GC 13.2 Remote Control

The System Operator may require Generators with Generating Plant above 10 MW to, within a reasonable time after giving notice in writing: (a) install remote control equipment ("RCE") that is adequate to enable the System Operator to remotely control:

a. the active power output of any generator; and

b. the reactive power output of any generator; and

Any RCE already installed in a Generating Plant to be upgraded, modified or replaced, by notice in writing to the relevant Generator provided that the existing RCE is, in the reasonable opinion of the System Operator, no longer fit for its intended purpose.

Unless agreed otherwise, the relevant Generator will be responsible for the following actions at the request of the System Operator:

a. activating and de-activating RCE installed in relation to any generator; and

b. setting the minimum and maximum levels to which, and a maximum rate at which, the System Operator will be able to adjust the performance of any generator using RCE.

GC 13.2.1 Communications Equipment

Generator shall provide electricity supplies for RME and RCE installed in relation to his generators capable of keeping such equipment available for at least eight hours following total loss of supply at the Point of Common Coupling for the relevant generator.

Generator shall provide communications paths (with appropriate redundancy) from the RME or RCE installed at any of his Generating Plant to a communications interface in a location reasonably acceptable to the System Operator at the relevant Generating Plant or generation control Centre.

The Generator shall provide, the telecommunications equipment as specified in Schedule 5 of the Generation Code. The selection and installation of items to be provided by the Generator in accordance with the prior written approval of System Operator, which approval shall not be unreasonably conditioned, withheld or delayed.

GC 13.2.2 Governor System

Each Generating Unit shall have a governor system which includes facilities for both speed and load control whether in manual or closed loop automatic generation control except where approved by the System Operator. The method of control must be agreed and approved by the System Operator

Generator shall adjust the governor system of a Generating Unit to ensure stable performance under all operating conditions with adequate damping.

The Generator shall advise the Single Buyer and System Operator of data regarding the structure and parameter settings of all components of the governor control equipment, including the speed/load operator, actuators (for example hydraulic valve positioning systems), valve flow characteristics, limiters, valve operating sequences and steam tables for steam turbine (as appropriate) in sufficient detail to enable the System Operator to characterize the dynamic response of these components for short and long term simulation studies. These data shall include a control block diagram in suitable form and proposed settings for the governor system for all expected modes of governor operation.

These parameter settings shall not be varied without prior approval of the System Operator.

GC 13.2.3 Voltage Support

System Operator has the responsibility to monitor and control the system voltages. Therefore, System Operator may issue a new voltage set-point to the Generator concerning scheduled voltage support requests. The System Operator will maintain a performance log for all Generators acknowledgments of such requests and a response is deemed provided at an appropriate time agreed on between the System Operator and the Generator.

Generator shall ensure that the excitation control system of a synchronous Generating Unit is capable of:

a. limiting Generating Unit operation at all load levels to within Generating Unit capabilities for continuous operation;

b. controlling Generating Unit excitation to maintain the short-time average Generating Unit stator voltage at highest rated level which shall be at least 5% above the nominal stator voltage (and is usually 10% above the nominal stator voltage);

A minimum performance requirement that shall be establish by System Operator for each for Generating Units which have an A.C. exciter, rotating rectifier or static excitation system, in accordance with acceptable international standards such as the IEEE and IEC. Refer IEEE Standard 115-2009 - Test Procedures for Synchronous Machines, for further information.

The Generator shall obtain the prior approval of the System Operator for the structure and parameter settings of all components of the Generating Unit excitation control system, including the voltage regulator, power system stabilizer, power amplifiers and all excitation limiters.

The Generator shall not change, correct or adjust the structure and settings of the excitation control system in any manner without prior written notification to System Operator. The System Operator may then require the Generator to conduct Generating Unit tests to ensure compliance with previous test and standards. The System Operator shall have the opportunity to witness these test, if wishes to do so.

GC 13.2.4 LVRT/HVRT

LVRT and HVRT monitoring at the Interconnection Point shall be enforced by the System Operator through on site disturbance recording. For verification of the behaviour of the VRPP plant with installed Active Power equal to or above 10 MW in the case of real voltage dips or voltage swells, a disturbance recorder must be installed at the Interconnection Point of the VRPP plant. The aim of this monitoring/recording is to ensure that the VRPP units behave in the same manner as shown in the VRPP simulations and/or tests, and meet the Transmission Code for LVRT and HVRT.

After a real event (voltage dip or voltage swell), the behaviour of the VRPP plant may be checked by System Operator for compliance based on the measurements available from the recording unit.

GC 13.2.5 Generation Dispatch and Shutdown Signal

System Operator reserves the right to send dispatch instructions to VRPPs, via phone or SCADA as per the VRPP's SCADA signals list, to reduce its output due to system reliability.

In the event that System Operator is required to shut down and disconnect a VRPP from the System Operator Transmission System:

On-Line VRPPs must be able to commence their shutdown sequence within five (5) minutes of receipt of a Dispatch Instruction from System Operator. The shutdown sequence shall be completed as soon as practical, but no longer than ten (10) minutes from the receipt of a Dispatch Instruction from System Operator.

If the System Operator Transmission System condition requires breaker or switch operations to disconnect a non-MW producing VRPP from the system, the disconnection shall be completed as soon as practical, but no longer than ten (10) minutes from the receipt of a Dispatch Instruction from System Operator. Once disconnected from the System Operator Transmission System, a VRPP shall wait for instructions from System Control Centre before reconnecting the system to the network. The VRPP shall complete as soon as practical, but no longer than ten (10) minutes, the required switching to return the system to a normal configuration after receiving the new Dispatch Signal from System Operator to do so.

After providing prior notice to System Operator, a VRPP plant may disconnect from the Transmission System at any time, if reasonable and practical, in the case that the condition or manner of operation of the System Operator Transmission System poses an immediate threat of injury or material damage to any person or equipment of the VRPP Units and/or project substation.

GC 13.2.6 Additional Monitoring and Control Requirements for VRPPs

In addition to the above where applicable, the following meteorological data will be required for wind and solar PV plants:

a. wind speed

b. wind direction

c. air temperature

d. air pressure

e. solar irradiance

GC 14 UNFORESEEN CIRCUMSTANCES, SYSTEM EMERGENCIES

GC 14.1 Unforeseen Circumstances

If circumstances arise which are not addressed by the Code, the System Operator, shall, to the extent practicable in the circumstances, consult promptly and in good faith with all affected Parties in an effort to reach agreement as to the required course of action. If such agreement cannot be reached in the time available the System Operator shall refer the matter to the OUR with a view to determining the course of action to be taken.

Whenever the OUR makes a determination, it shall do so having regard, wherever possible, to the views expressed by the Generators and the System Operator, in any event, to what is reasonable in the circumstances. Each Generator and the System Operator shall comply with the instructions given to it by the OUR as a consequence of such a determination, provided that the instructions are consistent with the technical parameters set out in the Code, the respective Licences and PPAs. The OUR shall promptly refer all unforeseen circumstances and any determinations to the Generation Code Review Panel for consideration.

GC 14.2 Force Majeure

All Parties should note that the provisions of the Code may be suspended in whole, or in part, pursuant to any directions or orders given by the OUR in situations of Force Majeure.

GC 15 GENERATION INTERCONNECTION STUDIES

Power system analysis studies shall be conducted by System Operator or third party consultant pre-approved by System Operator, according to the Study Guidelines outlined in the Transmission Code and using a suitable power system software such as PSS/E and DIgSILENT or equivalent. The final results and the used models, including the validated user model have to be handed over to the System. The studies must demonstrate the capability of the plant to meet all the System code requirements outlined in this section. The Plant model shall comprise all facilities necessary for the generation of power from the Generating Unit(s) to be integrated in the system model.

The following power system studies are to be conducted:

a. Load Flow Studies

b. Short Circuit Studies

c. Transient Stability Studies

d. Steady-State Stability Analysis

e. Voltage Stability Analysis

In addition to the above and due to the intermittent nature of the VRPP, additional power system studies as outline below but not limited to should be done:

a. Voltage Flicker

b. Harmonic Analysis

c. Phase Imbalance

d. Medium and Long Term Stability Study or Quasi Dynamic analysis

GC 15.1 Generator Dataset

The dataset that will be required to carry out the appropriate system studies and also to execute Dispatch Instructions can be found in sections of the Transmission, Distribution and Dispatch Codes as follow:

Transmission Code

a. Section TC 18 Transmission Data Registration

b. Schedules I

c. Schedules VI

d. Schedules VIII and

e. TC APPENDIX - Site Responsibility Schedule's

Distribution Code

Section DC 19 Distribution System Data Registration

Dispatch Code

Section DSC 16. Data to be exchanged between the System Operator and Generators.

SCHEDULE A: REQUIRED COMMUNICATION EQUIPMENT

The Communication Systems used for System Operations are in two basic forms –VHF Radio for general operational communications (including mobile units), and a point-to-point telephone system for Substations and Generating Stations operation. For switching operations, the primary form of communication is radio while the secondary communication is telephone. For all other operations, telephone is the primary form of communication and radio is the secondary form. Proper use of these facilities is described in detail in the System Operator's Policies and Procedures Manual for System Operation. However the following principles are especially noteworthy:

The VHF radio system should be operated in accordance with stipulated protocols.

Transmitter/receiver sets are located at all District offices, Power Stations, major Substations and in the Generator's Operating vehicles

Communication equipment should be properly maintained and any malfunction of such equipment be reported to System control promptly

In the event of loss of communication (including Public Telephone facilities) between a generating station and System Control, the Generator's management must assume full direction and control of the Station. All actions taken and their corresponding times must be logged and reported to system control as soon as communication is restored. In any such event the first priority is safety and then system integrity. The Generator shall not change the operations and shall maintain the last dispatch while maintaining safety.

Supervisory Control and Data Acquisition

The Supervisory Control and Data Acquisition (SCADA) System is currently used to monitor and record status and analogue values at relevant data collection points throughout the system. Required points for monitoring include circuit breakers, switches, potential transformers and current transformers.

The SCADA system performs constant scanning of all data points and logs a status update every two seconds, unless a significant non-transient change occurs that results in a monitored value exceeding its predefined limits, in which case the resolution of the data recorded is in milliseconds. It is therefore necessary that the monitoring/control devices installed at the Generating Station be capable of sub second response to a degree equal to or better than that of the System's SCADA equipment.

Required Communication Equipment

Each Generator shall install and maintain at each Generating Station at its sole cost and expense:

1. Compatible Remote Terminal Units ("RTUs") to allow interfacing of SCADA status and analog signals from the generating station to the centralized SCADA system at system control, specifically transmitting:

a. Three phase values of watts, vars, voltage, and current as well as bus bar frequency

b. Status (open, closed) of the relevant circuit breakers

2. Adequate Power Line Carrier Channels to System Control Centre for the purpose of telemetering, protection and telecommunications.

3. An extension of System Control Centre PBX System in the Generating Units control room to facilitate (hotline) voice communication between the Generator control room and System Control Centre.

4. Telecommunications facilities such as Internet and landline telephones in the Generating Units control room to transmit and receive telecopies/facsimiles and electronic mail to and from System Control Centre respectively.

5. UHF and VHF radio equipment to permit voice communication between the Generating Unit control room and System Control Centre.

6. Microwave equipment to transmit data to System Control Centre.

7. A synchronized digital GPS Clock to allow time stamping of all analog and status communications especially those logged by the Sequence of Events recorder.

8. Dictaphone with sufficient capacity and functionality to keep permanent time stamped operational communications. Procedures governing the use of the Dictaphone to be approved.

9.

SCHEDULE B: LOAD SHEDDING SCHEME

Setting of Under-frequency Relays

The Under-frequency Relay set points as at the date of this document are as follows:

Stage	Under-frequency Relay Setting
0	49.35
1	49.2
2	48.9
3	48.5
4	48.1

SCHEDULE C: RESERVE MARGIN POLICY

Spinning Reserve Policy

SYSTEM OPERATION POLICIES AND PROCEDURES

CLIENT: JAMAICA PUBLIC SERVICE COMPANY LIMITED — Ref. No. 8 Page: 1 of 1

SUBJECT: OPERATING SPINNING RESERVE POLICY — Effective Date:________

	Responsibility	Reference
The following details the company's spinning reserve policy.		
A minimum spinning reserve capacity of 30 MW should be planned to meet the daily system demand.	Operation Planning Engineer	
Consistent with the above policy, the following measures should be adopted:		
a) The Old Harbour units (OH2, OH3, OH4) and Hunts Bay B6 steam unit are to be limited to a maximum of 85% of their Maximum Continuous Rating (MCR). The difference between the reserve allocated by the above restrictions and the stipulated 30 MW operating spinning reserve is to be allocated across the system by means of an economic optimization process.	System Control Engineer	
b) Under normal circumstances a gas turbine should not be started with the spinning reserve above 30 MW. However, if the margin should fall below 30 MW, a gas turbine can be used to assist in maintaining a margin of spare plant.	System Control Engineer	Section 7.2
c) Gas Turbines should be used for quick load restoration following operation of under frequency relays. (At least two of the aeroderivative GTs (GTs 5, 7, 8, 9, 11) should be on remote standby for this purpose, unless they are required to meet the demand.	System Control Engineer/Bogue Operations Manager	
d) No single generator should be allowed to carry more than 27.7% of the total demand. This is in keeping with the system overload protection of 38%. Provisions for this is made in the ELD programme.	Operations Planning Engineer/System Control Engineer	

Approved By	Status	First Effective	Supercedes	Reviewed By
	Active	Dec 2006	Apr 03	Ricardo Case

4/09/05

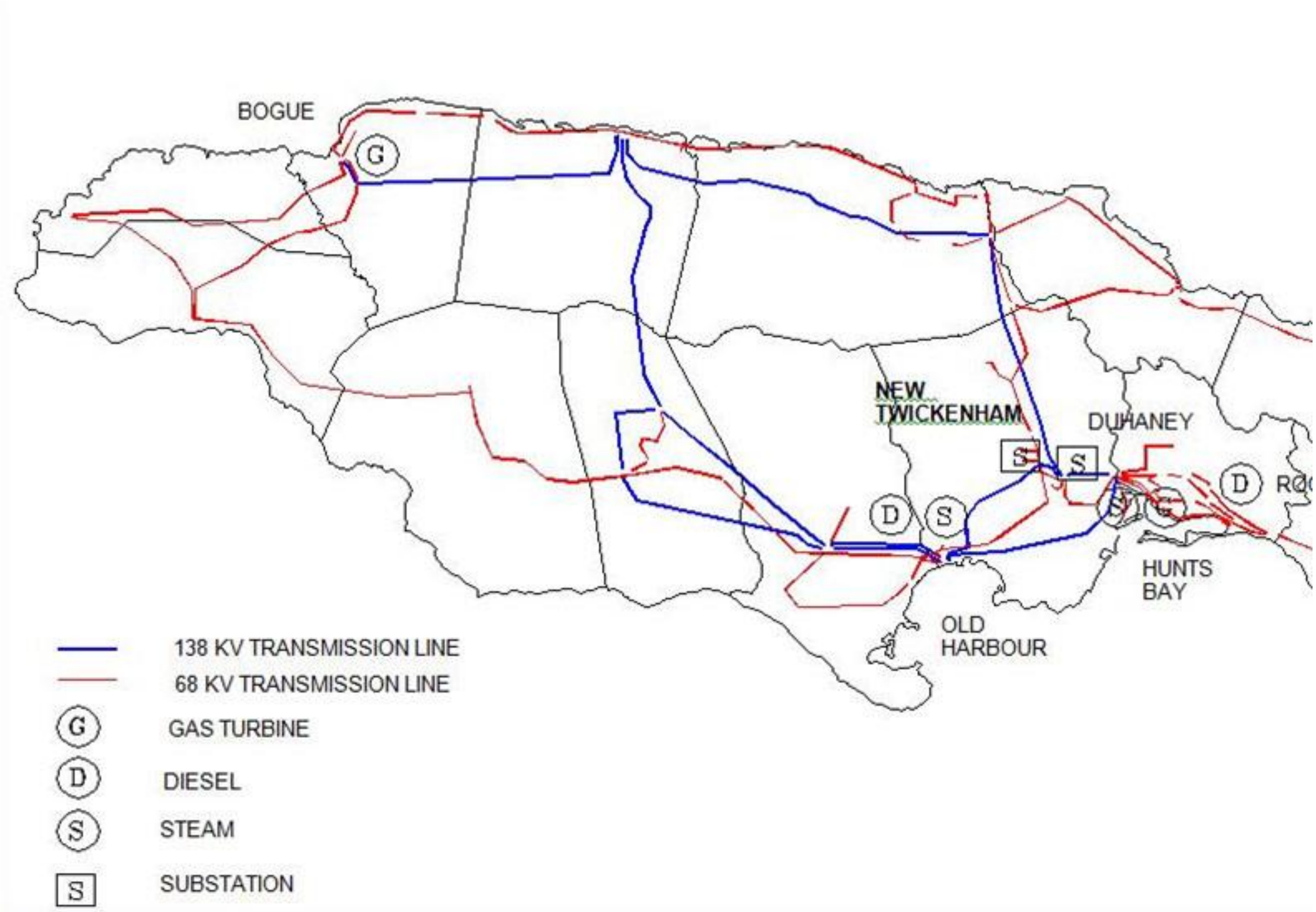
SCHEDULE D: EXISTING GENERATING SYSTEM

Unit	Capacity(MW)	Technology	Fuel Type	Location	Remarks
RF#1	20.0	Slow Speed Diesel	HFO	Rockfort	
RF#2	20.0	Slow Speed Diesel	HFO	Rockfort	
OH#1	30.0	Steam	HFO	Old Harbour	Out of service
OH#2	60.0	Steam	HFO	Old Harbour	
OH#3	65.0	Steam	HFO	Old Harbour	
OH#4	68.5	Steam	HFO	Old Harbour	
HB#B6	68.5	Steam	HFO	Hunt's Bay	
GT#5	21.5	ADO Fired Gas Turbine	ADO	Hunt's Bay	
GT#10	32.5	ADO Fired Gas Turbine	ADO	Hunt's Bay	
GT#3	21.5	ADO Fired Gas Turbine	ADO	Bogue	
GT#6	14.0	ADO Fired Gas Turbine	ADO	Bogue	
GT#7	14.0	ADO Fired Gas Turbine	ADO	Bogue	
GT#8	14.0	ADO Fired Gas Turbine	ADO	Bogue	
GT#9	20.0	ADO Fired Gas Turbine	ADO	Bogue	
GT#11	20.0	ADO Fired Gas Turbine	ADO	Bogue	
Bogue Combined Cycle	114.0	ADO-CCGT	ADO	Bogue	

Maggotty	6.0	Run of River Hydro		Maggotty	
Lower White River	4.75	Run of River Hydro		White River	
Upper White River	3.19	Run of River Hydro		White River	
Roaring River	4.05	Run of River Hydro		Roaring River	
Rio Bueno "A"	2.5	Run of River Hydro		Rio Bueno	
Rio Bueno "B"	1.1	Run of River Hydro		Rio Bueno	
Constant Spring Hydro	0.75	Run of River Hydro		Constant Spring	
JPPC – IPP	60.0	Slow Speed Diesel	HFO	Rockfort	
JEP – IPP	124.2	Medium Speed Diesel	HFO	Old Harbour	
WKPP – IPP	65.5	Medium Speed Diesel	HFO	Hunts Bay	
Wigton Wind Farm I	20.7	Wind Turbines		Wigton	Energy only
Wigton Wind Farm II	18.0	Wind Turbines		Wigton	Energy only
Munro College	0.25	Wind Turbines		Munro	
System Operator Munro Win	3.0	Wind Turbines		Munro	
Jamaica Broilers	as-available	Slow Speed Diesel	HFO	Spring Village	
JAMALCO	11.0	Steam – Cogen	HFO	May Pen	

JAMALCO	as-available	Alternative	St Jago, Clarendon

ADO	Automotive Diesel Oil
GT	Gas Turbine
HB	Hunts Bay
HFO	Heavy Fuel Oil
IPP	Independent Power Producer
JEP	Jamaica Energy Partners
JPPC	Jamaica Private Power Company
OH	Old Harbour
RF	Rockfort
WKPP	West Kingston Power Partners



Layout of Jamaica's Generation and Transmission System

SCHEDULE E: SYSTEM OPERATOR INTERCONNECTION CRITERIA

Generating Unit(s) Connected to the Jamaican Transmission System

	Category	System Operations Criteria/Parameters	Plant/Generating Unit Design Criteria	Comments
Transmission **System Security**	Interconnection Voltage	Generating Unit(s) at rated capacity >10MW shall be connected to the Transmission system at 69kV or 138kV.		The System Operator on basis of System Security Stability and Safety should determine the interconnection voltage
	Reliability of Generating Unit(s) System Interconnection Points	All substations shall have the capability to disconnect or separate, from the System, any transmission line and/or Generating Unit that is interconnected to the substation.	Substations (including Generation substations) with more than three (3) Transmission Lines or generating units shall be of a “breaker and a half configuration”.	
	Loss of Generation	For the loss of one transmission element there shall be no loss of generation > 60MW.	The loss of any single transmission element interconnecting a Generating Unit(s) shall not result in a loss of generation greater than 60MW. Therefore generation greater than 60MW shall be designed on the N-1 principle.	

	Category	Operations Mode	Unit	System Operations Criteria/Parameters	Plant/Generating Unit Design Criteria	Comments
Plant Performance	Frequency	Nominal	Hz	50	Generating plant and auxiliary apparatus shall be designed to operate at this nominal frequency (continuous operation).	Intermittent and type generating maintain active power per the turbine/ power curve characteristic
		Normal Operating Band	Hz	49.5 – 50.5	Maintain constant Active Power output at any load point. Generating plant and auxiliary apparatus shall be designed to operate in this range.	
		Abnormal	Hz	48.5 – 49.5 50.5 – 52.5	Maintain constant Active Power output at any load point. Plant and Apparatus shall be designed to operate in this range (continuous operation)	Intermittent and type generating define the limit at Generating Unit(s criteria for review by the SO.
			Hz	48.0 – 48.5	Maintain, for at least one (1) second, Active Power within 95% and 100% of output loading levels before abnormal frequencies occurred. Generating plant and auxiliary apparatus shall be designed to operate in this range.	

			Hz	<48.0	Generating Unit trip settings shall be as agreed with the System Operator.	
	Voltage	Nominal	KV	69kV or 138kV	Reactive power output shall be fully available under steady state conditions.	
		Normal Operating Band (± nominal kV)	%	± 5%	Reactive power output shall be fully available under steady state conditions (continuous operation). The Generating Unit shall not be affected by voltage changes in this operating band.	Generating plant reactive power induction generator provide their full power compensation w specified voltage bands (normal a
		Abnormal	%	± 10%	Reactive power output shall be fully available under steady state conditions	

	Category	Operations Mode	Unit	System Operations Criteria/Parameters	Plant/Generating Unit Design Criteria	Comments

Category	Operations Mode	Unit	System Operations Criteria/Parameters	Plant/Generating Unit Design Criteria	Comments
Negative Phase – Sequence Component of phase voltage	Normal	%	<1%	Sustained operation at any load (continuous operation)	
(Unbalance loading Withstand capability)	Abnormal	%	≤2%	Sustained operation at any load (continuous operation)	
Negative Phase - Sequence Component of phase voltage cont'd (Unbalance loading withstand capability)	Faults			Generating unit shall withstand, without tripping, the negative phase sequence loading incurred by clearance of a close-up phase-to-phase fault by system back-up protection on the Transmission System.	The System Operator relay settings up
Plant Output	Normal	MW	Rated Generating Unit output shall be provided in the interconnection or Power Purchase Agreement.	Supply rated Active Power (MW) at any point between limits 0.85 pf lagging and 0.95 pf leading at Generating Unit terminals. Reactive power output shall be fully variable between these limits.	Intermittent and type generating maintain Active output as per the turbine/generator characteristics.
Synchronization	Normal			1. Synchronize and parallel/load transfer with System without causing	

	Category	Operations Mode	Unit	System Operations Criteria/Parameters	Plant/Generating Unit Design Criteria	Comments
					voltage fluctuation at Interconnection Point >±5% of voltage at Interconnection Point. 2. Synchronize to System within voltage ±5% of nominal and frequency 50±0.5Hz	
		Abnormal			synchronize to System within voltage ±10% of nominal and frequency 50±0.5Hz	
Controls	Frequency Control	Normal			Each Generating Unit shall be capable of contributing to frequency control by continuous modulation of Active Power supplied to the Transmission system. The unit shall be fitted with a fast-acting speed governing system that shall have an overall speed droop characteristic of five (5) percent or less.	Applicable on a C basis for intermittent renewable type Generating Plant. The droop setting

				The speed Governor Deadband shall be no greater than 0.1 Hz.	
	Voltage Control	Normal		Each Generating Unit shall be capable of contributing to voltage control by continuous changes to the Reactive Power supplied to the Transmission system. Automatic Voltage Regulator: Deadband: not exceeding 0.5% Controls: Capability to control voltage continuously between 90% and upper limit of rated voltage of the Generating Unit from no load to full load. This range shall be covered linearly in approximately 1 minute.	Applicable on a C basis for intermittent renewable type g plant.
	Excitation Control	Normal		Provide Constant Terminal voltage control of the synchronous generating unit without instability over the entire operating range of the unit Excitation System (Large Signal response): Voltage response Time: less than 0.1	Applicable on a C basis for intermittent renewable type Generating Plant.

	Category	Operations Mode	Unit	System Operations Criteria/Parameters	Plant/Generating Unit Design Criteria	Comments
					second for a voltage step change not to exceed 5% in terminal voltage Ceiling Voltage: minimum 160% of Generating Unit rated load field voltage.	
Protection	Generating Unit Protection	Abnormal		Protect against: - Loss of Excitation - Under Excitation - Unbalanced Load Operation - Stator Phase Faults and Earth Faults - Reverse Power - Unit Over and Under frequency - Thermal Overload: Stator Over Temperature, - Generating Unit Over speed - Restricted Earth Fault	Meet system protection requirements for all synchronous Generating Units.	Protection required by asynchronous Generating Plant and reviewed by System Operator.

	Generating Unit Step Up Transformer (GSU)	Protect against: - Phase and earth faults (HV and LV) within the GSU zone - Transformer Tank Sudden pressure, - Differential Current - Backup protection if	Meet system protection requirements for all GSU.

	Category	Operations Mode	Unit	System Operations Criteria/Parameters	Plant/Generating Unit Design Criteria	Comments

	Category	Operations Mode	Unit	System Operations Criteria/Parameters	Plant/Generating Unit Design Criteria	Comments
				protection) The Generating Unit owner to provide breaker fail signal to System Operator (System Operator) switchyard		
Fault Cleaning Times	Transmission Bus (point of System interconnection)	Maximum time	Milliseconds (ms)	To be provided in Power Purchase Agreement (PPA) documents. In the absence of the requirement in PPA documents, fault clearing time (from fault inception to arc extinction) shall not be slower than: 69kV – 120ms 138kV – 100 ms	Meet or exceed system fault clearing times. The Generating Unit shall remain transiently stable and interconnected to the system without tripping for a close-up solid three phase fault or any unbalanced short circuit fault on the Transmission System up to the maximum total fault clearance time. During the period of the fault the Generating Unit shall generate maximum reactive current without exceeding the transient	

				rating limit of the generating unit.
Fault Levels	Transmission bus (point of System Interconnection)	Amps (A)	To be provided in Power Purchase Agreement (PPA) documents.	The maximum fault levels at the System Interconnection Point shall be below 80% of the interrupting capacity of substation and plant apparatus determined using Generating Unit transient impedances.

The owner of the Generating Unit(s) is required to submit to the System Operator all Generating Unit and Generating Unit step up (GSU) transformer parameters upon completion of plant, apparatus and equipment designs.

SCHEDULE F: LOW VOLTAGE RIDE THROUGH CHARACTERISTIC

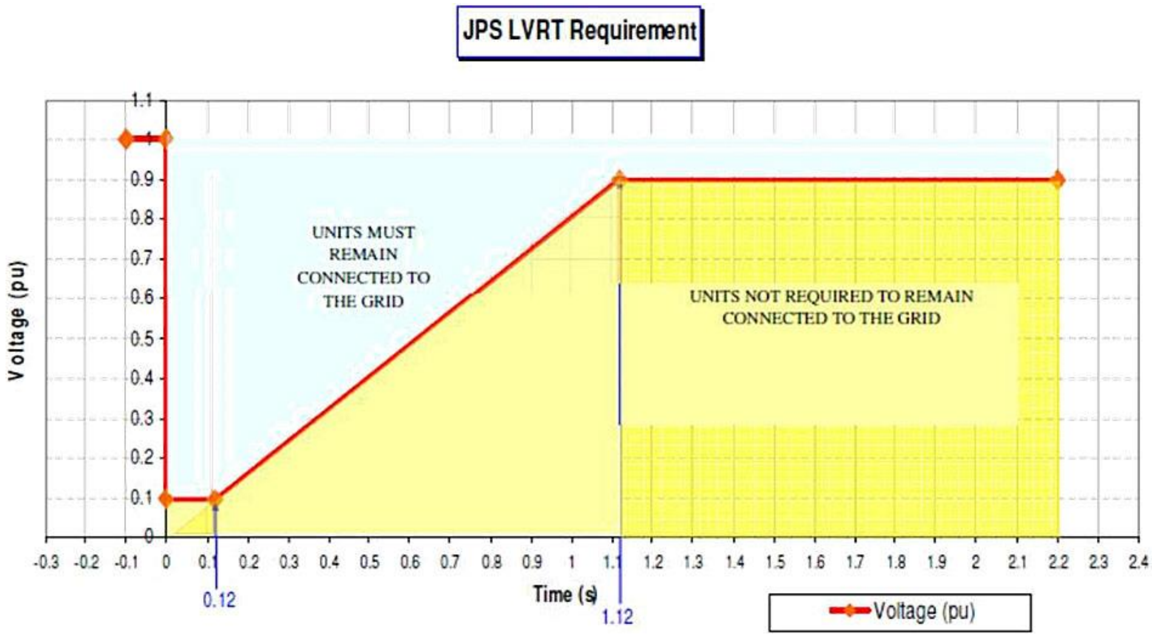


Figure GC - S1 Low Voltage Ride Through Characteristics

SCHEDULE G: HIGH VOLTAGE RIDE THROUGH CHARACTERISTICS

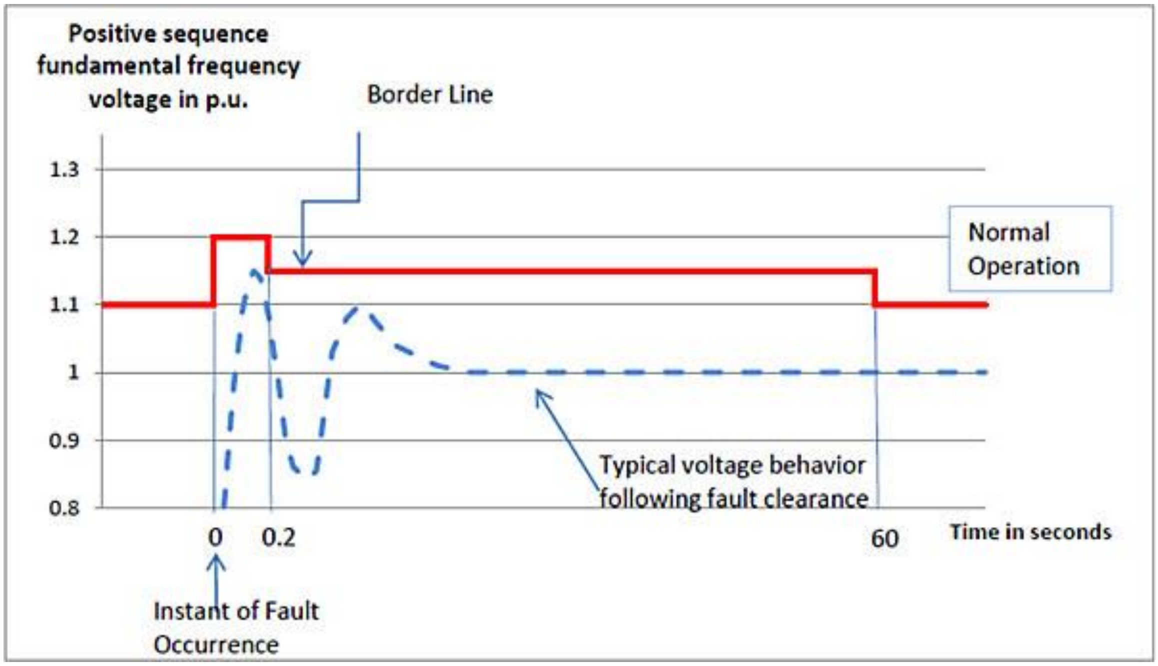


Figure GC – S2 High Voltage Ride Through Characteristics

Transmission Code

TC

TC 1 SCOPE

This Transmission Code sets out the procedures and principles governing the Operation of the Jamaica Transmission System and applies to the conveyance of electricity by means of the Transmission System, which includes electric power lines operating at 69kV and higher, including the secondary circuit breakers and up to the outgoing Isolators at Transmission Substations transforming to 24kV, 13.8kV and 12kV. The Code provides the guidelines controlling the development, maintenance and Operation of an efficient, coordinated and economic Transmission System in Jamaica.

This Transmission Code sets out the procedures and principles governing the System Operators relationship with all Users of the System Operators Transmission System.

The Transmission Code shall be complied with by the System Operator and existing and potential Generators and Users connected to or seeking to Interconnect to the System.

TC 2 GENERAL REQUIREMENTS

This Transmission Code contains the procedures to provide an adequate, safe and efficient service to all parts of Jamaica, taking into account a wide range of operational circumstances. It is however necessary to recognize that the Transmission Code cannot address every possible situation. Where such unforeseen situations occur the System Operator shall act as a reasonable and prudent operator in the pursuance of any or a combination of the following General Requirements:

a. to protect the safety of the public and employees;

b. the need to preserve the integrity of the System;

c. to prevent damage to the System;

d. compliance with conditions under its Licence;

e. compliance with the Act;

f. compliance with the Distribution Code;

g. compliance with the Generation Code;

h. compliance with the Dispatch Code; and

i. compliance with the Supply Code.

Users shall provide such reasonable co-operation and assistance as the System Operator reasonably request in pursuance of the General Requirements.

TC 3 TRANSMISSION PLANNING

TC 3.1 Purpose and Scope

Section 41-(1) of the Act provides that the Minister shall be responsible for planning the development of the System, which planning shall include:

a. the collection of data from electricity sector participants;

b. consultations with the Office, the Single Buyer and other electricity sector participants; and

c. the conduct of any relevant forecast.

This provision further requires that the planning process for transmission and distribution, consider the location of renewable and other generation sources, taking into account the potential for electrification of rural areas. The provision also requires that all licence holders must comply with a request made by the Minister for information for the purposes of executing his planning responsibility under this section and failure to comply with a request under this sub-section, without reasonable cause, shall be an offence.

TC 3.2 Planning Process

TC 3.2.1 Introduction

The Transmission Code anticipates a three phase process for planning: long term midterm, and operational (short term) planning.

The Ministry of Energy The Minister responsible for energy is responsible for long-term planning, leading the integrated resource planning process that establishes the policy guidelines for grid development.

The System Operator is responsible for mid-term and operational planning.

TC 3.2.2 Long Term Planning

The 2015 Electricity Act Sections 4(a) and 7(1) contain new provisions that charge the Minister of Energy with responsibility for planning the development of the electricity System under the management of the System operator, including integrated resource planning, the collection of data from electricity sector participants and the conduct of any relevant forecast. The Electricity Act section 7(2) requires that the planning process specifically consider the location of renewable and other generation sources, taking into account the potential for electrification of rural areas. Finally, Electricity Act section 7(3) mandates that all electricity sector participants must comply with a request from the Minister for information for the purposes of executing his planning responsibility.

The Ministry has informed OUR and electricity stakeholders that the Ministry will develop detailed procedures for development of an integrated resource plan, engaging key electricity sector stakeholders in a collaborative development process. The IRP process design is now underway, and will be published after the Grid Code publication in September 2016. It is anticipated that the long-term planning sections of the Generation, Transmission, and Distribution Codes may be revised soon after publication to fully support the Ministry's IRP development process, once finalized, and may be further revised in the future to adjust for changes in the IRP process.

The Grid Code long-term planning requirements anticipate coordinated data collection system and ICT/software requirements among the Ministry, OUR, Licensee, and all IPPs required to support the IRP long term planning process, to assure that the Ministry receives the information required for its planning duties, and to minimize any inefficiencies.

The Ministry will lead the long term planning process, establishing the objectives and metrics of the IRP, and communicating those to all stakeholders, informing the public (including OUR and Licensee) of the status and outcome of the planning process.

It is anticipated that Transmission and Distribution Planning studies will be developed by the Licensee and approved for use by the Ministry, with rates impacts analyzed by the OUR.

It is anticipated that the Licensee will develop Load Forecasting projections and that the Ministry would develop assumptions and inputs for use in the Load Forecast, informing OUR of the Load projections.

It is anticipated that the Ministry will be responsible for supply technologies modelled within the study and feasibility studies used to determine viable technologies are the responsibility of the Ministry. Licensee approves the integration of any technologies for operational purposes and contracting for resources; OUR will review rates impacts. the Ministry will approve contracting for third party resources to ensure consistency with Integrated Electricity Planning results.

Table 3-1 summarizes the anticipated IRP Inter-Agency Roles and Responsibilities.

Table 3-1: Inter-Agency Roles and Responsibilities

Responsibility	the Ministry	Licensee	OUR (Rates)
Objectives and Metrics	Develop	Inform	Inform

Transmission & Distribution Planning Studies	Approve	Develop	Review for rates
Load Forecasting: Assumptions/Inputs supplied by the Ministry	Approve	Develop	Inform
Stakeholder Process: communication & policy	Develop	Inform	Inform
Supply Technologies and Feasibility Studies	Develop	Approve	Review for rates
Third Party Supply/Demand Contracts	Approve	Develop	Approve rates
Sales Forecasting	Approve	Develop	Approve rates
Energy Efficiency and Demand Programs	Develop	Inform	Approve rates
Policy Action Plans	Develop	Inform	Inform
Environmental Impacts – NEPA compliance management interface with Licensee	Develop	Inform	Inform

OUR will request the Grid Code Review Panel to prioritize development of detailed Long-Term Planning provisions consistent with the the Ministry planning process, once published.

TC 3.2.3 Mid-Term planning.

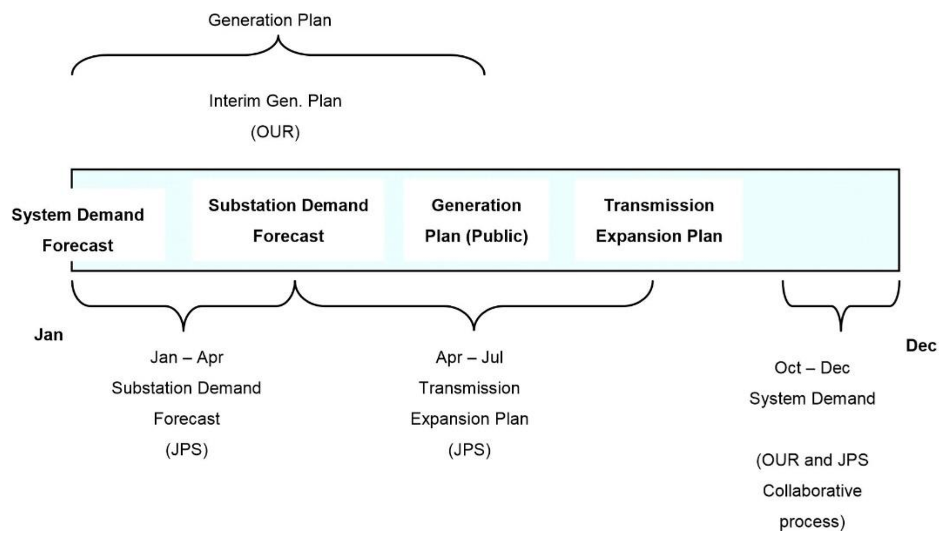
The System Operator is responsible for mid-term planning in compliance with the requirements of the Codes and the policy objectives set forth in an approved Integrated Resource Plan.

TC 3.2.4 Operational Planning

The System Operator is responsible for operational planning in compliance with the requirements of the Codes and the policy objectives set forth in an approved Integrated Resource Plan.

TC 3.3 Planning Timescales

The planning process above should operate on an annual cycle. The cycle commences with the development of the System demand forecast in Q4 (year n), then the development of the Substation Demand Forecast in Q1 (year n+1), and is completed with the production of the Least Cost Expansion Plan in Q3 (year n+1).



Interconnection Related Planning Studies shall be undertaken outside the above process, but new load information will be used to inform the demand forecasts. The timescales required to undertake the new Interconnection studies necessary to plan the System vary depending on the driver for the studies and the ability to obtain consented routes.

TC 3.4 Transmission System Security Standards

This Sub- section of the Code sets out the Transmission Security Standards against which the System Operator will plan the Transmission System.

TC 3.4.1 Normal Conditions

The System Operator shall plan, design and operate the Transmission System such that under normal steady state conditions, prior to any fault, there shall not be:

a. equipment loadings exceeding the pre-fault rating;

b. voltages outside ±5% of nominal values on all 69 kV and 138 kV buses;

c. voltages outside ±5% of nominal values on Generator buses; or

d. system instability.

TC 3.4.2 Contingency Conditions

The System Operator shall plan, design and operate the Transmission System such that the System is secured against the following contingencies.

TC 3.4.3 Single Forced Outage

The loss of any single transmission element or interbus transformer, except in cases of radial lines, shall not affect the System's ability to adequately supply the required demand of its sub-station(s).

TC 3.4.4 Generating Unit Outage

The loss of any single transmission element connecting a Generating Unit to the Transmission System shall not result in a loss of generation greater than 60 MW. This implies that Interconnection for Generators of greater than 60 MW shall be designed on the N-1 principle.

TC 3.4.5 Voltages

Under contingency conditions voltages shall be maintained as follows:

Voltages at all Generator terminal buses are to be within ±5% of nominal voltage; and Voltages at all 69 kV and 138 kV buses are to be within – 10% of nominal voltages.

TC 3.5 Load Power Factor

The System will be planned for a normal load power factor of 0.95 with a voltage planning criteria of –5% for normal Operation and ±10% for contingency conditions.

TC 3.6 Thermal Loadings

Under contingency conditions, transmission line loading of up to 110% of rated continuous rating for 30 minutes (Emergency Rating) may be used. 138/69 kV Interbus Transformer loadings may not exceed nominal rating.

TC 3.7 Spinning Reserve

The System Operator shall have in place a Spinning Reserve policy, subject to review by the OUR, at all times. The policy shall seek to ensure that the spinning reserve margin is adequate to cover the loss of a small generator without the loss of load. Loss of large generators could result in loss of demand, which under these circumstances shall not be deemed to be a breach of the transmission security standards. For further details of the Spinning Reserve Policy refer to Generation Code Schedule C "Reserve Margin Policy". Loss of demand under these circumstances shall not be deemed to be a breach of the Transmission Code.

TC 3.8 Fault Levels

The maximum fault levels in the System should be below 80% of the rated interrupting capacity of the circuit breakers determined using the generators transient impedances.

TC 3.9 Frequency Criteria

Maintain frequency within the limit of 50 Hz ± 0.2 Hz, with a dead band of less than 0.1Hz. In case of outage of some elements, the System may resort to under frequency load shedding scheme to control the frequency, as outlined in Schedule B of the Generation Code.

TC 3.10 Network Stability

The Transmission System should remain stable when subjected to severe System disturbances, such as the loss of a large generating plant, or Short Circuit condition.

TC 3.10.1 Fault Clearing Time

The Fault Clearance Time for a Short Circuit fault, shall not be longer than:

a. 100 ms for 138 kV; and

b. 120 ms for 69 kV.

TC 3.11 Transmission System Resiliency (Reserved)

How to best minimize and mitigate System damage and outages due to extreme weather events and how to best assure rapid restoration of power following any unavoidable outages.

TC 3.12 PLANNING PROCEDURES

TC 3.12.1 General

The System Operator shall conduct Transmission System planning studies consistent with the planning process and established planning criteria to ensure the Safety, Reliability, Security, and Stability of the Transmission System for the following:

a. preparation of the Transmission Least Cost Expansion Plan for submission to the OUR and the Minister;

b. evaluation of Transmission System reinforcement projects; and

c. evaluation of any proposed User Development, which is submitted to the System Operator in accordance with an application for an Interconnection Agreement or an Amended Interconnection Agreement for loads or generators.

The Transmission System planning studies shall be conducted to assess the impact on the Transmission System of any Demand Forecast or any proposed addition or change of Equipment or facilities in the Transmission System and to identify corrective measures to eliminate the deficiencies in the Transmission System.

The Transmission System planning studies shall be conducted periodically as required to assess:

a. the behaviour of the Transmission System during normal and Outage contingency conditions; and

b. the behaviour of the Transmission System during the electromechanical or electromagnetic transient induced by disturbances or switching operations.

Power System analysis studies shall be conducted by Licensee or third party consultant pre-approved by Licensee, according to the Study Guidelines outlined in the Transmission Code (TC), and using a suitable power System software such as PSS/E and DIgSILENT. The final results and the used models, including the validated user model have to be handed over to the System. The studies must demonstrate the capability of the plant to meet all the grid code requirements outlined in this the Transmission Code. The model shall comprise all facilities necessary for the generation of power from the generating plant to be integrated in the System model.

TC 3.13 Load Flow Studies

Load flow studies shall be performed to evaluate the behaviour of the Transmission System for the existing and planned Transmission System facilities under forecasted maximum and minimum Load conditions over a planning horizon of up to 10 years. These studies will determine the impact on the Transmission System of the Interconnection of new Generating Plants, Loads, or transmission lines.

Load/power flow simulations shall be conducted in line with the planning criteria, to include both normal and contingency conditions. The results of the studies will provide, information regarding equipment loading (lines or transformers) and bus voltages together with any deficiencies in reactive support.

Sensitivity analyses shall also be carried out to determine the impact that any proposed changes will have on the Operation of the Transmission System at other times than peak and minimum loads.

For new transmission lines, any condition within the planning criteria that produces the maximum power flows through the existing and new lines shall be identified and evaluated in order to determine any remedial measures necessary.

TC 3.14 Short Circuit Studies

Short circuit studies shall be performed to evaluate the effect on Transmission System Equipment associated with the Interconnection of new Generating Plants, transmission lines, and other facilities that will result in increased fault duties for Transmission System Equipment. These studies shall identify the Equipment, such as switchyard devices and substation buses that could be permanently damaged when the current exceeds the Equipment design limit. The studies shall also identify the circuit breakers, which may fail when interrupting possible short circuit currents.

Short Circuit studies are also required to allow for the correct setting of protection relays on which depends the stability of the Transmission System under fault conditions.

Short-circuit studies shall be performed for all bus bars on the Transmission System for different feasible generation, load, and System circuit configurations. These studies shall identify the most severe conditions that the Transmission System Equipment may be exposed to. Alternative Transmission System circuit configurations shall be studied to reduce the short circuit currents within the limits of existing Equipment. Such changes in circuit configuration shall be subjected to load flow and stability analysis to ensure that the changes do not cause steady-state load flow or stability problems.

The fault type to be consider, should include but not limited to the various fault type listed below:

a. three phase

b. double line

c. double line to ground and

d. single line to ground

The results shall be considered satisfactory when, at the planning stage, the short-circuit currents are within 80% of the design limits of Equipment and the proposed Transmission System configurations are suitable for flexible and safe Operation.

TC 3.15 Transient Stability Studies

Transient Stability studies shall be performed to verify the impact of the Interconnection of new Generating Plants, transmission lines, and substations and changes in Transmission System circuit configurations on the ability of the Transmission System to seek a stable operating point following a transient disturbance. Transient Stability studies shall simulate the outages of critical Transmission System facilities such as major transmission lines and large Generating Units. The studies shall demonstrate that the Transmission System performance is satisfactory if:

a. the Transmission System returns to a stable condition after any Single

b. outage Contingency for all forecasted Load conditions; and

c. the Transmission System remains controllable by other means, such as operator intervention and automatic tripping of demand or generation after multiple outage contingencies within the planning criteria.

Transient stability studies shall be conducted for all new transmission lines or substations and for the Interconnection of new Generating Units equal to or larger than [60] MW connected to the Transmission System. In other cases, the System Operator shall determine the need to perform transient Stability studies.

TC 3.16 Steady-State Stability Analysis

Transient stability is the inherent ability of a power System to remain stable and maintain network synchronism when subjected to severe disturbances. The starting point of the stability studies is the steady-state conditions (determined by the load flow study). System parameters that can be derived from a steady-state stability study includes the rotor (stability phase) angle of Generators, real (MW) and reactive (MVAR) power flows, and bus voltages.

Stability studies shall be carried out to check the dynamic performance of the Transmission System in the following circumstances:

a. load shedding by under-frequency relays following tripping of large Generators:

   i. normal System Operation with the network intact, for both the day and evening peak;

   ii. after System separation occurs, and

   iii. System minimum load condition.

b. slow clearance of faults due to mal-Operation of the protection systems; and

c. the loss of strategic Transmission circuits including transformers.

The ability of the System to withstand the most severe fault shall be tested. The most onerous fault is defined as the application of a solid three phase fault or a single line to ground fault close to the main generating stations. The Critical Fault Clearing Time (CFCT) should also be examined to determine the response of the System to a prolonged fault.

The stability studies shall identify solutions, such as the installation of power System stabilizers or the identification of safe operating conditions.

TC 3.17 Voltage Stability Analysis

Periodic studies shall be performed to determine if the Transmission System is vulnerable to voltage collapse under heavy loading conditions. A voltage collapse can proceed very rapidly if the ability of System s Reactive Power supply to support System voltages is exhausted. The studies shall identify solutions such as the installation of dynamic and static Reactive Power compensation devices to avoid vulnerability to voltage collapse. In addition, the studies shall identify safe Power System operating conditions where vulnerability to voltage collapse can be avoided until solutions are implemented.

TC 3.18 Data Requirements

TC 3.18.1 General

A critical part of all the studies mentioned above is the large volume of input data that is required by each study. This data set is necessary for the development of accurate mathematical models that can mimic the System real-time response. Refer to section 18 for data registration detail Schedules

TC 3.18.2 Demand

In order to carry out load flow studies, substation loads can be represented by their constant real (MW) and reactive (MVAR) power requirements. However, voltage and transient stability studies require complex models for substation loads. In the absence of these complex models the System Operator shall continue to use the constant power model for its transient and voltage stability studies

Demand forecast are required to enable the network to be developed in a coordinated and economic manner. A consumption forecast using an econometric regression methodology is considered suitable for this. This forecast of unit consumption is then to be developed into a peak demand forecast for each substation: this demand data shall then be used in the System studies outlined in section TC 3.

The overall process for development of the grid wise forecast is illustrated below. This process is undertaken on an annual basis.

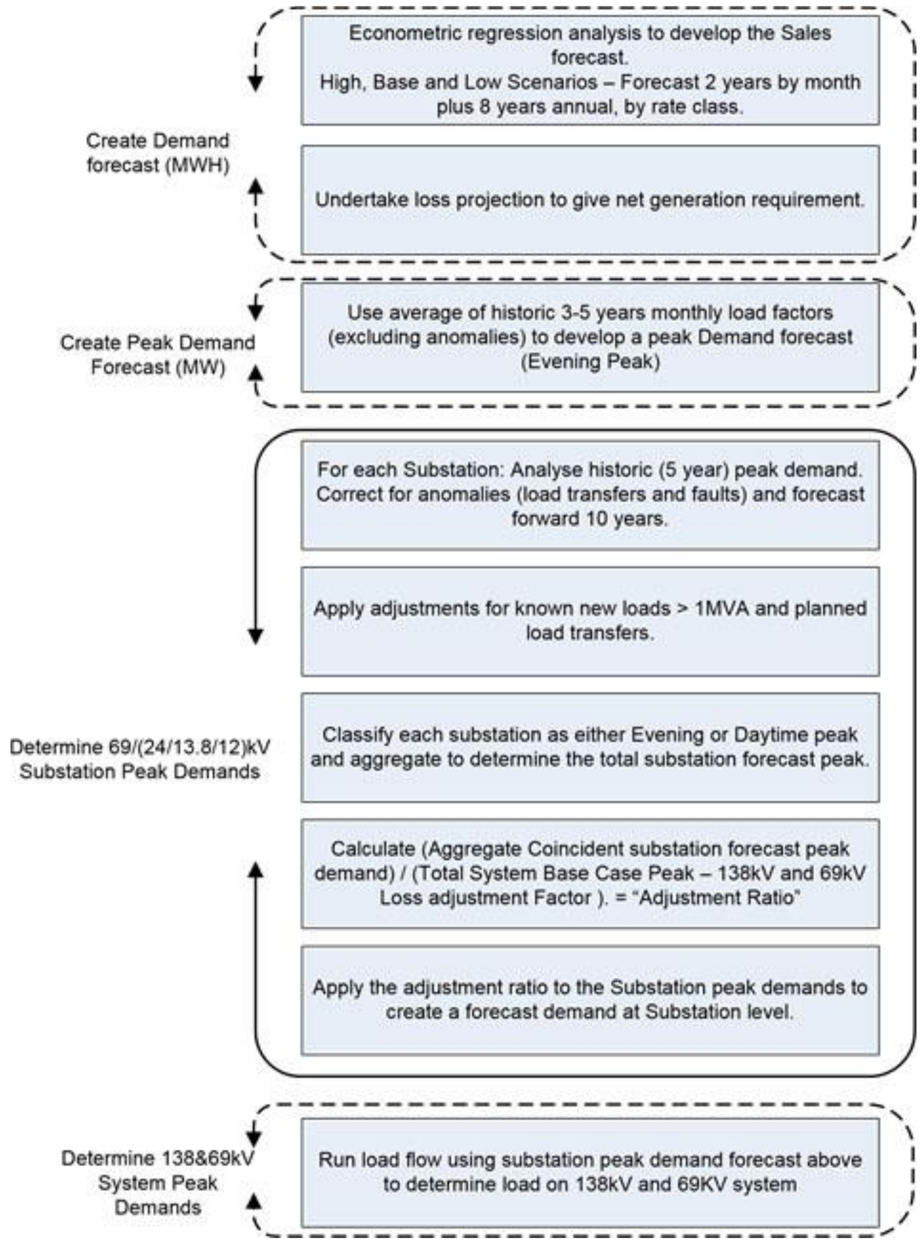


Figure TC 3.7 System and Substation Demand Forecast Process

TC 3.18.3 Transmission System Data

The System Operator shall have available all the network data relevant to the Transmission System itself. This network data is set out in section Transmission System Data Registration and includes among others, the following:

TC 3.18.4 Transformers

The primary input data for transformers includes MVA rating, primary and secondary winding voltages, windings connection, sequence impedances, X/R ratio, tap ranges, tap settings, emergency ratings.

TC 3.18.5 Transmission Lines

Transmission lines are generally represented by single-phase models with equivalent series impedances (resistance-inductance combinations) between line terminals and equivalent shunt admittances at each terminal. The primary input data required among other things are line voltage, conductor type, type of construction, thermal ratings, emergency rating and sequence impedances.

TC 3.18.6 Generating Units

Generating Units are modelled by their real and reactive power capabilities for steady state analysis. For dynamic analysis more detailed mathematical models are required for generators, exciters and governor control systems. The generators are represented by their mathematical model which includes the synchronous, transient and sub transient reactance and inertia constants. The excitation and governor control systems are modelled by their excitation and general-purpose governor control model respectively. The appropriate dynamic dataset and block diagram model should be provided, where necessary.

TC 3.18.7 Other System Parameters

In order to carry out Transient and dynamic stability Studies, data are required on the settings of overcurrent, distance under frequency and under voltage relays. Data are also required for circuit breaker operating time. Transient and dynamic stability studies required information on relay and breaker times and operating sequences. In order to develop a reliability data bank outage rates and durations for all major equipment are also necessary.

TC 3.18.8 User System Data

In the context of this Long – Term Transmission System Planning, User means a customer interconnected directly to the /Transmission System at the 69 or 138 kV voltage level.

Any User applying for Interconnection or modification of an existing Interconnection to the Transmission System shall submit to the System Operator the data required for the Transmission System in accordance with section TC 3.17.4. These data requirements are also set out in the Interconnection section of this Code.

All Users shall also notify the System Operator of any changes that take place in the parameters of his equipment at the Interconnection Point.

User shall also submit in writing to the System Operator each year in week [4] his best estimate of Energy and Demand at his Interconnection Point(s) projected for five (5) succeeding years.

The System Operator will make available to the User or potential User Planning data as will enable such Users to determine the effect of their systems of Transmission System development.

TC 4 MAINTENANCE STANDARDS

All Plant and Apparatus on the System shall be operated and maintained in accordance with Prudent Utility Practice and in a manner that shall not pose a threat to the safety of employees or the public.

The System Operator shall establish a Transmission System Maintenance Policy which shall be reviewed and approved by the OUR. Provision shall also be made for annual independent assessment and validation of the philosophy and operation of system protective mechanisms.

TC 4.1 Competency of Staff

The System Operator shall have in place training polices that serve to ensure that persons operating, maintaining, testing and controlling the System Operator Transmission and Distribution Systems are competent for the tasks to be undertaken. The policies shall include refresher training at appropriate intervals to maintain the currency of the training.

All persons operating, maintaining, testing and controlling the System Operator Transmission and Distribution Systems, shall have received appropriate training to ensure competency for the tasks that they will be undertaking and refresher training at appropriate intervals to maintain the currency of the training.

The System Operator shall maintain records of training given and issue certificates indicating the areas of competency of the persons trained.

TC 4.2 Requirement for Inspection

All Plant and Apparatus that will form part of the Transmission System will only become part of the Transmission System following inspection and approval by a License Electrical Inspector within the approved category.

TC 5 TRANSMISSION INTERCONNECTION

TC 5.1 General

This Transmission Interconnection section specifies the normal method of Interconnection to the Transmission System and the minimum technical, design and operational criteria which must be complied with by any User or prospective User. For the purpose of the Transmission Interconnection Code, User refers to both Generators and Large Customers connected to the Transmission System.

In addition, details specific to each User's Interconnection may be set out in a separate Interconnection Agreement/Interconnection Agreement or in some cases a Power Purchase Agreement. The Interconnection Conditions set out in this Transmission Interconnection Code are complementary to these Agreements.

Conditions of PPAs established before the Code shall control over a conflicting Code provision.

All interconnection costs and responsibility shall normally be borne by the User connected to the Transmission System, unless specified otherwise by an Interconnection Agreement, or policy, or as dictated by the OUR.

TC 5.2 Objective

The objective of section TC 5 is to ensure that by specifying minimum technical, design and operational criteria the basic rules for Interconnection to the Transmission System shall provide guidance for all System Users and shall enable Licensee in its capacity as System Operator and System Users to comply with its statutory and Licence obligations.

This Interconnection Code applies to Licensee in its capacity as System Operator and to the following:

a. Generators connected to the Transmission System;

b. Licensee in its capacity as Distribution System operator at the Interconnection Points to the Transmission System;

c. Large Customers directly connected to the Transmission System, and

TC 5.3 Method of Interconnection

TC 5.3.1 General

The System Operator in consultation with the User shall determine the optimum Interconnection method on the basis of several technical and economic factors including:

a. Geographical considerations including proximity to the Transmission System;

b. Generating Facility MW capacity and/or maximum Demand to be supplied;

c. Supply voltage;

d. Reliability considerations;

e. Standby or auxiliary power requirements;

f. Substation configuration; and

g. Costs.

It should be noted that it will not be technically or economically practicable to achieve uniformity of the method of Interconnection. In all cases however, Prudent Utility Practice will guide the method adopted.

The provisions relating to interconnecting to the Transmission System are contained in each Interconnection Agreement and Power Purchase Agreement with a User and include provisions relating to both the submission of information and reports relating to compliance with the relevant Interconnection Agreement and Power Purchase Agreement for that User, Safety Rules, commissioning programmes, Operation Diagrams and approval to interconnect.

Prior to the Completion Date under the Interconnection Agreement, the following are to be submitted by the User:

a. updated Planning Code data with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for items such as Demand;

b. details of the protection arrangements and settings including a Protection and Control Single Line Diagram;

c. copies of all Safety Rules and Local Safety Instructions applicable at Users Sites which shall be used at the System Operator/User interface;

d. information to enable the System Operator to prepare Site Responsibility Schedules on the basis of the provisions set out in Appendix A;

e. an Operation Diagram for all HV Apparatus on the User side of the Interconnection Point;

f. the proposed name of the User Site (which shall not be the same as, or confusingly similar to, the name of any Licensee Site or of any other User Site);

g. a list of Safety Coordinators;

h. a list of the telephone numbers for Joint System Incidents at which senior management representatives nominated for the purpose can be contacted and confirmation that they are fully authorized to make binding decisions on behalf of the User;

i. a list of managers who have been duly authorized to sign Site Responsibility Schedules on behalf of the User; and

j. information to enable System Operator to prepare Site Common Drawings.

TC 6 POWER QUALITY STANDARDS

TC 6.1 Power Quality

For the purpose of this section of the Transmission Code, Power Quality shall be defined as the quality of the voltage, including its frequency and the resulting current that are measured in the Transmission System during normal conditions. The standards applicable to Power Quality are set out in the System Operator s Power Quality Policy, and Licensee System Operation Policy No 2 operational Standards of Security of Supply which shall be approved by the OUR and amended from time-to-time. For ease of reference sections of the Licensee System Operation Policy No. 2 are summarized below.

"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 outside the acceptable tolerance of the nominal value of 50±0.2 Hz

b. voltage magnitudes are outside their allowable range of variation;

c. harmonic frequencies are present in the System;

d. the Magnitude of the phase voltages are unbalanced.

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 over-voltages are present in the Transmission System".

TC 6.2 Frequency Variations

The frequency of the Transmission System shall be nominally 50 – 0.2 Hz and consistent with Licensee System Operation Policy No 2. The System Operator may reset the target frequency based on System conditions between 49.5 Hz and 50.5 Hz.

Under some conditions the System frequency could rise to 52.5 Hz or fall to 48.0 Hz and this shall be taken into account in the design of Plant and Apparatus.

TC 6.3 Voltage Variations

The voltage on the Transmission System at each Interconnection Site with a User shall normally remain within ±5% of the nominal value. The minimum voltage is -10% and the maximum voltage is +10% but voltages between +5% and +10% shall not last longer than 15 minutes unless abnormal conditions prevail.

The voltage on the lower voltage side of transformers at Interconnection Sites with Users shall normally remain within the limits –5% of the nominal value unless abnormal conditions prevail.

TC 6.4 Voltage Waveform Quality

All Plant and Apparatus connected to the Transmission System, and that part of the Transmission System at each Interconnection Site, should be capable of withstanding distortions as outlined in the System Operator’s Power Quality Policy.

TC 6.5 Exceptional Conditions

Some events such as System faults which involve the HV network (Transmission System) or a generating plant or faults that lead to loss of more than one generating set in the System or where a Significant Incident has occurred or during constrained operating conditions such as light load conditions and shortage of Active/Reactive power, can result in variations outside the normal power quality standards as outlined in sections TC 6 and its sub-sections. During these events, the System Operator shall be relieved of its obligation to comply with the System conditions referenced in the aforementioned sections, subject to the approval of the OUR.

TC 7 PLANT AND APPARATUS RELATING TO INTERCONNECTION SITES

TC 7.1 General Requirements

All Plant and Apparatus relating to the User/System Operator at the Interconnection Point, shall be compliant with the conditions in this section.

The design of connections between any Generating Unit and the Transmission System shall be as set out in section 1 Interconnection Conditions of the Generation Code section GC 2. The design of interconnections between the Transmission

System and Large Customers shall be in accordance with Condition 24 of the Licence and this Code.

TC 7.2 Substation Plant and Apparatus

All circuit breakers, switch disconnectors, Earthing Devices, power transformers, Voltage Transformers, reactors, Current Transformers, surge arresters, bushings, neutral Equipment, capacitors, line traps, coupling devices, external insulation and insulation co-ordination at the User/Licensee Interconnection Point shall be constructed, installed and tested in accordance with the current edition at the time of construction of the following codes and technical standards, or their international equivalents and Prudent Utility Practice:

ACI	American Concrete Institute
ANSI	American National Standards Institute
ASCE	American Society for Civil Engineers
ASME	American Society for Mechanical Engineers
ASNT	American Society for Non-Destructive Testing
ASTM	American Society for Testing Materials
AWS	American Welding Society
BSJ	Bureau of Standards Jamaica
IEC	International Electromechanical Commission
IEEE	Institute of Electrical and Electronic Engineers
ISO	International Organization for Standardization
NBCJ	National Building Code of Jamaica
NEC	National Electric Code
NEMA	National Electric Manufacturers Association
NEPA	National Environment and Planning Agency (Jamaica)
NESC	National Electric Safety Code
NETA	National Electric Testing Association
NFPA	National Fire Protection Association
OSHA	Occupational Safety and Health Administration
SSPC	Steel Structures Painting Council

UL	Underwriters Laboratory

Plant and Apparatus shall be designed, manufactured and tested in premises certified in accordance with the quality assurance requirements of ISO 9001 or equivalent.

TC 7.3 Generator Interconnection Points

The requirements for the design of Interconnection Points between Generators and the Transmission System are set out in the Generation Code. For information the following two sections are extracted from the Generation Code.

The voltage level at which the Generating Unit(s) are connected to the Transmission or Distribution System shall be dependent on but not limited to the size and number of units and the other factors that determine the Interconnection Point.

Subject to other technical considerations, Generating Units with a Rated Capacity of 10 MW or above shall be connected to the Transmission System at 69 kV or 138 kV. Generating Units with a Rated

Capacity of below 10 MW may be connected to either the Transmission System at 69 kV or 138 kV or the primary Distribution System at 24 kV or less. The chosen method of Interconnection shall be determined by the System Operator on the grounds of System security, stability and safety.

All Substations shall have the capability to disconnect or separate, from the Transmission System, any transmission line and/or Generating Unit which is interconnected to the Substation. For reasons of ensuring safety and reliability of Operation, generating substations with more than three transmission lines or Generating Units interconnected to them shall be of a "breaker and a half' configuration. The Substation shall be equipped with all requisite protection measures necessary to meet the System Operator's System protection standards as set out in sub-section 2.2.4 of the Generation Code.

TC 7.4 Interconnection Points to Distribution System or Large Customers

TC 7.4.1 Protection Arrangements

Protection of Distribution Systems and Large Customers directly supplied from the Transmission System must meet the minimum requirements referred to below:

The clearance times for faults on the Transmission System or equipment directly connected to the Transmission System from fault inception to circuit breaker arc extinction, shall be set out in an Interconnection Agreement where applicable but shall not be slower than:

a. 100 milliseconds (ms) for faults cleared by bus bar protection at 69 kV and 138kV; and

b. 100 ms for faults cleared by ultra-high speed directional comparison protection on 69 kV and 138 kV overhead lines. Slower fault clearance times for faults may be agreed but only if System requirements permit.

For the event of failure of the protection systems provided to meet the above fault clearance time requirements, back-up protection shall be provided by the User. The System Operator shall also provide back-up protection on the System, which shall result in a fault clearance time slower than that specified for the User back-up protection so as to provide discrimination.

For connections with the Transmission System, the back-up protection shall be provided by the User with a fault clearance time not slower than 350ms for faults on the User Apparatus.

TC 7.4.2 Fault Disconnection Facilities

Where no System Operator circuit breaker is provided at the User Interconnection Point, the User must provide the System Operator with the means of tripping all the User circuit breakers necessary to isolate faults or System abnormalities on the Transmission System. In these circumstances, for faults on the User System, the User protection should also trip higher voltage System Operator circuit breakers.

TC 7.4.3 Automatic Switching Equipment

Where automatic reclosure of circuit breakers controlled or operated by the System Operator is required following faults on the User System, automatic switching equipment shall be provided as necessary.

TC 7.4.4 Relay Settings

Protection and relay settings shall be coordinated across the Interconnection Point to ensure effective disconnection of faulty Apparatus. The process for the coordination of relay settings shall be defined by the System Operator and shall allow for annual third party independent assessments and validations.

TC 7.4.5 Work on Protection Equipment

Where the System Operator owns the bus bar at the Interconnection Point, no bus bar protection, AC or DC wiring (other than power supplies or DC tripping associated with the Users Apparatus) shall be worked upon or altered by User personnel in the absence of a representative of the System Operator.

TC 7.4.6 Neutral Earthing

At 138 kV the higher voltage windings of three phase transformers and transformer banks connected to the Transmission System must be star connected with the star point suitable for Interconnection to earth. The earthing and lower voltage winding arrangement shall be such as to ensure that the Earth Fault Factor requirement shall be met on the Transmission System.

TC 7.4.7 Under Frequency Relays

As required under the Code, suitable arrangements shall be made to facilitate automatic low frequency disconnection of Demand. Technical requirements relating to Under Frequency Relays are listed in Schedule B of Appendix A.

TC 7.4.8 Configuration of Substations

All Substations shall have the capability to disconnect or separate from the Transmission System, any transmission line and/or Generating Unit which is interconnected to the Substation.

For reasons of ensuring safety and reliability of Operation, Substations with more than three transmission lines or Generating Units interconnected to them shall be of a "breaker and a half' configuration. The Substation shall be equipped with all requisite protection measures necessary to meet the System Operator's System protection standards as set out in section TC 7.6 and in the document "Protective Relaying Philosophy and Practices" issued by the Licensee.

TC 7.5 Protection Requirements

The protective systems to be applied to Generating Units are set out in the Generation Code sub-section GC 2.2.4 and shall, as a minimum, have protection against the following incidents unless specifically agreed with the System Operator:

a. loss of excitation;

b. under excitation;

c. unbalanced load Operation;

d. stator phase faults and earth faults;

e. reverse power protection;

f. main Generating Unit Step-up Transformer (GSU) phase and earth faults, HV and LV;

g. Station service transformer phase and earth faults, HV and LV;

h. transformer tank sudden pressure;

i. backup protection in the event that external phase and earth faults are not cleared by remote protection System;

j. backup protection in the event of circuit breaker failure to operate;

k. Generating Unit over and under frequency;

l. generator over speed;

m. stator over temperature;

n. rotor over temperature; and

o. restricted earth fault.

The Protective systems to be applied to the User's Equipment at the Interconnection 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 Transmission System.

The System Operator and the User shall be solely responsible for the protection systems of electrical equipment and facilities at their respective sides of the Interconnection Point.

The Fault Clearance Time shall be specified in the Interconnection Agreement.

The Fault Clearance Time for a fault on the Transmission System where the User s Equipment is connected, or on the User System where the System Operator s Equipment is connected, shall not be longer than: a. 100 ms for 138 kV; and 120 ms for 69 kV.

Where the Users Equipment is connected to the Transmission System and a circuit breaker is provided by the User (or by the System Operator) at the Interconnection Point to interrupt fault currents at any side of the Interconnection Point, a circuit breaker fail protection shall also be provided by the User (or the System Operator).

The circuit breaker fail protection shall be designed to initiate the tripping of all the necessary electrically-adjacent circuit breakers and to interrupt the fault current within the next 250 milliseconds, in the event that the primary protection System fails to interrupt the fault current within the prescribed Fault Clearance Time.

Where the automatic reclosure of a circuit breaker is required following a fault on the User System, automatic switching Equipment shall be provided in accordance with the requirements specified in the Interconnection Agreement.

The reliability of the protection scheme to initiate the successful tripping of the circuit breakers that are associated with the faulty Equipment shall be consistent with Prudent Utility Practices.

The System Operator may require specific Users to provide other protection schemes, designed and developed to maintain Grid Security, or to minimize the risk and/or impact of disturbances on the Grid.

TC 8 SITE RELATED CONDITIONS

TC 8.1 General

In the absence of agreement between the Parties to the contrary, construction, commissioning, control, Operation and maintenance responsibilities for the Plant and/or Apparatus follow ownership.

TC 8.2 Responsibilities for Safety

Before Interconnection to the Transmission System the System Operator and the User shall enter into a written agreement as to the Safety Rules to be used for work on Plant and/or Apparatus at the Interconnection Point.

TC 8.3 Site Responsibility Schedules

In order to inform site operational staff and the System Operator s Control Engineers of agreed responsibilities for Plant and/or Apparatus at the Operational Interface, a Site Responsibility Schedule shall be produced for System Operator and Users with whom they interface.

The format, principles and basic procedure to be used in the preparation of Site Responsibility Schedules are set down in Appendix A.

TC 8.4 Operation Diagrams

An Operation Diagram shall be prepared by the User for each Interconnection Site at which an Interconnection Point exists in accordance with Appendix B.

The Operation Diagram shall include all HV Apparatus and the connections to all external circuits and incorporate numbering, nomenclature and labelling, as set out in section TC 15. At those Interconnection Sites where SF6 gas-insulated metal enclosed switchgear and/or other SF6 gas-insulated HV Apparatus is installed, those items must be depicted within an area delineated by a chain dotted line which intersects SF6 gas-zone boundaries. The nomenclature used shall conform to that used on the relevant Interconnection Site and circuit.

The Operation Diagram (and the list of technical details) is intended to provide an accurate record of the layout and circuit interconnections, ratings and numbering and nomenclature of HV Apparatus and related Plant.

TC 8.5 SF6 Gas Zone Diagrams

An SF6 Gas Zone Diagram shall be prepared for each Interconnection Site at which a Interconnection Point exists where SF6 gas-insulated switchgear and/or other SF6 gas-insulated HV Apparatus is utilised. They shall use, where appropriate, the graphical symbols shown in Appendix B. The nomenclature used shall conform to that used in the relevant Interconnection Site and circuit.

TC 8.6 Preparation of Operation and SF6 Gas Zone Diagrams

Each party shall provide to the other Party an Operation Diagram and details of the SF6 Gas Zones on its side of the Interconnection Point. The Party owning the Interconnection Site is then responsible for the preparation of a composite Operation Diagram and SF6 Gas Zone diagrams for the site.

TC 8.7 Changes to Operation and SF6 Gas Zone Diagrams

When either Party has decided that it wishes to install new HV Apparatus or it wishes to change the existing numbering or nomenclature of its HV Apparatus at a Interconnection Point it shall one month prior to the installation or change, send to the other Party a revised Operation Diagram of that Site, incorporating the new HV Apparatus to be installed and its numbering and nomenclature or the changes, as the case may be.

TC 8.8 Validity

The composite Operation Diagram prepared by the System Operator or the User shall be the definitive Operation Diagram for all operational and planning activities associated with the Interconnection Site. If a Dispute arises as to the accuracy of the composite Operation Diagram, a meeting shall be held at the Interconnection Site, as soon as reasonably practicable, between System Operator and the User, to endeavor to resolve the matters in dispute.

TC 8.9 Site Common Drawings

Site Common Drawings shall be prepared for each Interconnection Site and shall include Interconnection Site layout drawings, electrical layout drawings, common protection/control drawings and common services drawings.

In the case of a User Interconnection Site, the System Operator shall prepare and submit to the User, Site Common Drawings for the System Operator side of the Interconnection Point in accordance with the requirements of the Interconnection Agreement.

The User shall then prepare, produce and distribute, using the information submitted by the System Operator Site Common Drawings for the complete Interconnection Site in accordance with the requirements of the Interconnection Agreement.

In the case of a System Operator Site, the User shall prepare and submit to the System Operator Site Common Drawings for the User side of the Interconnection Point in accordance with the requirements of the Interconnection Agreement.

The System Operator shall then prepare, produce and distribute, using the information submitted by the User, Site Common Drawings for the complete

Interconnection Site in accordance with the requirements of the Interconnection Agreement.

TC 8.10 Changes to Site Common Drawings

When the System Operator or a User becomes aware that it is necessary to change any aspect of the Site Common Drawings at an Interconnection Site it shall notify the other Party and amend the common site drawings in accordance with the procedure set out in sub-section TC 8.9.

If the change can be dealt with by notifying the other Party in writing of the change and for each party to amend its copy of the Site Common Drawings then each party shall so amend.

TC 8.10.1 Validity of Site Common Drawings

The Site Common Drawings for the complete Interconnection Site prepared by the User or the System Operator as the case may be, shall be the definitive Site common drawings for all operational and planning activities associated with the Interconnection Site. If a Dispute arises as to the accuracy of the Site Common Drawings, a meeting shall be held at the Site, as soon as reasonably practicable, between the System Operator and the User, to endeavor to resolve the matters in dispute.

TC 8.11 Access

The provisions relating to access to System Operator Sites by Users, and to User Sites by the System Operator shall be set out in each Interconnection Agreement with the System Operator and each User.

In addition to those provisions, where a System Operator Site contains exposed HV conductors, unaccompanied access shall only be granted to individuals holding an Authority for Access issued by the System Operator.

TC 8.12 Maintenance Standards

All Plant and Apparatus at the Interconnection Point shall be operated and maintained in accordance with Prudent Utility Practice and in a manner that shall not pose a threat to the safety of any personnel or cause damage to the Plant and Apparatus of the System Operator or the User.

The User shall maintain a log containing the test results and maintenance records relating to its Plant and Apparatus at the Interconnection Point and shall make this log available when requested by the System Operator.

The System Operator shall maintain a log containing the test results and maintenance records relating to its Plant and Apparatus at the Interconnection Point and shall make this log available when requested by the User.

TC 8.13 Site operational Procedures

The System Operator and Users at an Interconnection Point shall make available staff to take necessary Safety Precautions and carry out operational duties as may be required to enable work/testing to be carried out and for the Operation of Plant Connected to the Transmission System.

TC 8.13.1 Switching Instructions

High Voltage switching shall only be carried out with the permission of the System Control Engineer except for agreed routine switching or in case of System Emergencies. Persons required to carry out high voltage switching must be specifically certified and authorized by the System Operator to carry out such switching.

The following procedures shall be adhered to when carrying out complex switching operations:

a. when switchgear, normally operated to the instruction of the System Control Engineer has been operated without instruction from him, the operator concerned shall notify the System Control Engineer immediately. Switchgear normally operated to the instruction of the System Control Engineer shall not be closed without his permission;

b. the System Control Engineer shall ensure that any instruction for switching issued by him is repeated phrase by phrase as received and at the termination of the message is read back to him in full by the recipient; and

c. any instruction issued by the System Control Engineer relating to the Operation of switchgear shall, be written down and every such instruction shall be repeated phrase by phrase as received. At the termination of the message it shall be read back in full to sender to ensure that the instruction has been accurately received.

Instructions from the System Control Engineer shall be carried out without delay and at the time of completing, the Operation or sequence of operations shall be reported back to the System Control Engineer.

An operator shall inform the System Control Engineer immediately of any objection to any instruction. The System Control Engineer shall then investigate the matter and if necessary refer it to higher authority endowed with the necessary powers of authority, to make a determination on such matters.

TC 9 OPERATIONAL COMMUNICATIONS

TC 9.1 Introduction

Section TC 9 sets out the requirements for the exchange of information in relation to operations on the Transmission System which have had (or may have had) or will have (or may have) an operational Effect:

a. on the Transmission System in the case of an Operation on a User System; and

b. on a User System in the case of an Operation on the Transmission System;

c. where no requirement for communication is specified in any other section of the Transmission Code.

Section TC 9 also sets out the procedure for issue of warnings in the event of a risk of serious and widespread disturbance of the whole, or part of, the Transmission System.

TC 9.2 Objective

The exchange of information is needed in order that the implications of the Operation can be considered and the possible risks arising from it can be assessed and appropriate action taken by the relevant party in order to maintain the integrity of the System. TC 9 does not seek to deal with any actions arising from the exchange of information, but merely with the exchange of information.

TC 9.3 Requirement to notify operations

The following are examples of situations where notification shall be required if they will have an operational Effect:

a. the implementation of a planned outage of Plant and/or Apparatus;

b. the planned Operation (other than, in the case of a User, at the instruction of the System Operator) of any circuit breaker or isolator or any sequence or combination of the two;

c. voltage control;

d. where an operational Instruction to be issued may have an effect on another User's System, Plant or Apparatus;

e. where Plant is expected to be operated in excess of its rated capability and may present a hazard to Persons;

f. where there is an expectation of abnormal operating conditions;

g. where there is increased risk of inadvertent Operation of protection; and

h. in relation to major testing, commissioning and maintenance.

TC 9.4 Operations on the Transmission System

In the case of an Operation on the Transmission System that will have or has had an operational Effect on the System of another User, the System Operator shall notify the User who's User System will be, is, or has been affected.

TC 9.5 Operations on a User System

In the case of an Operation on the User System that will have or has had an operational Effect on the Transmission System, the User shall notify the System Operator. Following notification by the User, the System Operator shall notify any other Users who's Systems will be, are, or have been affected.

TC 9.6 Nature of Notification for an Operation

In the case of an Operation on the Transmission System which will have or may have an operational Effect on a User System, the System Operator shall notify the User whose System will or may be affected. The recipient may ask questions to clarify the notification and the notifying Party shall use its reasonable endeavors to provide the necessary information.

In the case of an Operation on a User System which will have or may have operational Effect on the Transmission System, the User shall notify the System Operator. The recipient may ask questions to clarify the notification and the notifying party shall use its reasonable endeavors to provide the necessary information to the System Operator who shall notify any other Users on whose Users Systems the Operation will or may have an operational Effect.

TC 9.7 Form of Notification

A notification and any response to any questions of an Operation which has arisen independently of any other Operation or of an Incident, shall be of sufficient detail to describe the Operation and to enable the recipient of the notification to reasonably consider and assess the implications and risks arising and shall include the name of the individual reporting the Operation on behalf of the System Operator or the User. The recipient may ask questions to clarify the notification and the sender shall, insofar as it is able, answer any questions raised.

The notification shall, if either party requests, be recorded by the sender and dictated to the recipient, who shall record and repeat each phrase as it is received and on completion of the dictation shall repeat the notification in full to the sender who shall confirm that it has been accurately recorded.

TC 9.7.1 Timing

A notification under section TC 9 must be given as far in advance as practicable and in any event shall be given in sufficient time as shall reasonably allow the recipient to consider and assess the implications and risks arising.

TC 9.7.2 Warnings

A warning shall be issued by the System Operator (usually by telephone or other electronic means) to Users who may be affected when the System Operator anticipates there is a risk of widespread and serious disturbance to the whole, or part of, the Transmission System. Where the warning is given by telephone or other electronic means, the System Operator shall issue a written confirmation as soon as reasonably practicable thereafter.

The warning shall contain such information as the System Operator reasonably considers to be necessary in order to explain the nature and extent of the anticipated disturbance to the User provided that sufficient time is available to the System Operator prior to the issue of the warning and that such information is available to the System Operator

For the duration of a warning each User in receipt of the warning shall take the necessary steps to warn its operational staff and maintain its Plant and/or Apparatus in the condition in which it is best able to withstand the anticipated disturbance.

Scheduling and Dispatch in accordance with the Dispatch Code may be affected during the period covered by a warning. Further provisions on this are contained in the Dispatch Code.

TC 9.8 System Control

Where a Generator’s System (or part thereof) is, by agreement, under the control of the System Operator, then for the purposes of communication and co-ordination in operational timescales the System Operator may (for those purposes only) treat that Generator’s s System (or part thereof) as the System Operator s System but between the System Operator and Generator, it shall remain to be treated as the User s System.

TC 10 DEMAND CONTROL

TC 10.1 Introduction

This section TC 10 is concerned with the provisions made by the System Operator and procedures to be followed by the System Operator and Users to permit a reduction in Demand in the event that there is insufficient Generation available to meet Demand in all or any part of the Transmission System and/or in the event of problems on the Transmission System, including, without limitation, in the event of both a steady state shortfall of generation and a transient shortfall of generation following a sudden loss of generation.

TC 10.2 Objectives

The objectives are as follows;

To identify different methods of Demand Control and the procedures governing their implementation; and to clarify the obligations of the System Operator and Users as regards the development of procedures, and exchange of information, required for the implementation of Demand Control.

The System Operator shall ensure that all Parties affected by Demand Control are treated equitably and that Demand Control is used as a last resort.

TC 10.3 Methods of Demand Control

Demand Control is implemented in a number of ways, including:

a. shedding of Demand by automatic Under-Frequency Relays;

b. emergency manual demand shedding; and

c. planned rotating Demand Shedding.

TC 10.3.1 Interruptible loads

The obligations of the System Operator and Users in respect of these means of Demand Control are set out below in DSC 5.4, DSC 5.5 and DSC 5.6. All plans and implementation of Demand de-energisation shall give due consideration to critical Customers.

TC 10.3.2 Shedding of Demand by Automatic Under-Frequency Relays

The System Operator shall use Automatic Demand shedding by Under Frequency Relays to address short-term imbalances in the Generation Capacity and Demand situation, following the tripping of Generation beyond the Spinning Reserve value. It is a method of safeguarding the stability of the Transmission System when other actions, such as the use of the Operating Margin, have failed to stabilize or hold the Frequency within required Operating Limits.

TC 10.3.3 Emergency Manual Demand Shedding

The System Operator may implement Emergency Manual Demand Shedding to maintain the stability of the Transmission System, to cover a developing Generation shortfall or to relieve overloads or depressed voltages in the Transmission System or a part of it.

TC 10.3.4 Planned Rota Demand Shedding

In the event of a sustained period of shortfall in the Generation and Demand balance, either for the Transmission System as a whole or for significant parts of the System, the System Operator shall implement manual shedding of Demand on a rotating basis.

When implementing Planned Rota Demand Shedding the System Operator shall use reasonable measures to ensure that available power is shared among affected Parties on an equitable basis subject to consideration of critical customers. Groups of Customers can be de-energized for periods of up to [4] hours, after which their supplies shall be re-energized and another group of Customers de-energized.

TC 10.4 Procedures

The procedures for manual load shedding and the settings for Under Frequency Relays are set out in the following documents:

Engineering Instruction No 1.6 Load Shedding associated with Generating Plant Deficiency (Appendix B); and System Operation Policy and Procedure No 11 Controlled Load Shedding (Appendix C).

TC 11 SYSTEM CONTROL

TC 11.1 Control responsibilities

The System Operator and Users shall jointly agree and outline in writing schedules specifying the responsibilities for control of Equipment. These shall ensure that only one party is responsible for any item of Plant or Apparatus at any one time.

The System Operator and each User shall at all times have nominated a Control Person or persons responsible for the co-ordination of safety from the System pursuant to this sub-section TC 11.1

TC 11.2 Control Documentation

The System Operator and Users shall maintain a suitable System of documentation which records all relevant operational events that have taken place on the System or any other User System connected to it and the co-ordination of relevant safety precautions for work.

All documentation relevant to the Operation of the System, and safety precautions taken for work or tests, shall be held by the System Operator and the appropriate User for a period of not less than five years.

TC 11.3 System Diagrams

Diagrams illustrating sufficient information for Control Persons to carry out their duties shall be exchanged by the System Operator and the appropriate User.

TC 11.4 Communications

Where the System Operator reasonably specifies the need, suitable communication systems shall be established between the System Operator and other Users to ensure the control function is carried out in a safe and secure manner.

Where the System Operator reasonably decides a backup/alternative routing of communication is necessary to provide for the safe and secure Operation of the System the means shall be agreed with the appropriate Users.

Schedules of telephone numbers/call signs shall be exchanged by the System Operator and the appropriate User to enable control activities to be efficiently coordinated.

The System Operator and appropriate Users shall establish 24 hour availability of personnel with suitable authorization where the joint operational requirements demand it.

Where a Generator's System (or part thereof) is, by agreement, under the control of the System Operator, then for the purposes of communication and co-ordination in operational timescales the System Operator may (for those purposes only) treat that Generator's s System (or part thereof) as the System Operator s System but between the System Operator and Generator, it shall remain to be treated as the User s System.

TC 12 CONTINGENCY PLANNING

TC 12.1 Introduction

This Transmission Code requires the System Operator to develop a strategy to be implemented in Emergency Conditions of Major System Failure.

The System Operator shall have adequate policies and procedures in place to respond to a Total System Shutdown or major System Incident that will have widespread implications for electricity supply to the population. Users shall be aware of these policies and procedures, and cooperate fully in their implementation, through which the System Operator can return the System to normal operating conditions.

TC 12.2 Objective

The objectives of section TC 12 are:

a. to require the System Operator to develop a general restoration strategy to adopt in the event of Total System Shutdown or major System Incident;

b. to require the System Operator to produce and maintain comprehensive System restoration procedures covering Total System Shutdowns and major System Incidents;

c. to provide for the cooperation of Users with the formulation and execution of System restoration procedures;

d. to provide for the development and implementation of communications between the System Operator and Users when dealing with a System Incident; and

e. to ensure the System Operator and User personnel who will be involved with the implementation of System Restoration Procedures, are adequately trained and familiar with the relevant details of the procedures.

TC 12.3 Scope

In addition to the System Operator, section TC 12 applies to:

a. Generators;

b. Large Customers.

TC 12.4 System Restoration Strategy

The System Operator shall develop a System Restoration Strategy to be implemented in Emergency Conditions such as Total System Shutdown and other major System Incidents. The overall objectives of the System Restoration Strategy shall be as follows:

Restoration of the Transmission System and associated Demand in the shortest possible time, taking into account Generator capabilities, and Transmission System operational constraints;

Re-synchronization of parts of the Transmission System which have lost synchronism with each other; and

to provide for effective communication routes and arrangements to enable senior management representatives of the System Operator and Users, who are authorized to make binding decisions on behalf of the System Operator or a User to communicate with each other during a System Incident.

The System Restoration Strategy shall provide for the detailed implementation of the following:

Notification by the System Operator to Users that a Total System Shutdown or a Major System Incident has occurred and that the System Operator intends to implement System restoration procedures;

Identification of separate groups (Power Islands) of Generators together with complementary local Demand; and step by step integration of these Power Islands into larger sub-Systems to return the Transmission System to normal operating conditions.

The System Restoration Strategy shall also provide for the issue of any dispatch instructions necessitated by the System conditions prevailing at the time of the System Incident.

TC 12.5 System Restoration Procedures

In the event of emergency conditions such as a Total System Shutdown of the Transmission System, the System Operator shall issue an Alert as set out in to notify Users that it intends to implement System Restoration Procedures. The System Operator shall notify Users prior to the commencement of the System Restoration Procedures of the particular System Restoration Strategy to be implemented for that System Incident.

The System restoration procedures shall be developed and maintained by System Operator in consultation with other Users as appropriate in accordance with Prudent Utility Practice.

The Code Review Panel shall ensure that appropriate System restoration procedures are in place.

The System Restoration Procedures shall provide for:

procedures to establish an Emergency Operation Centre immediately following a major System Incident;

a decision on the location of the Emergency Operation Centre; and

the operational responsibilities and requirements of an Emergency Operation Centre, noting that such an Emergency Operation Centre shall be the focal point for communication and the dissemination of information between System Operator and senior management representatives of relevant Users.

The complexities and uncertainties of recovery from a Total System Shutdown of the Transmission System require the System restoration procedures to be sufficiently flexible so as to accommodate the full range of prevailing Generator and Transmission System operational possibilities and constraints.

TC 12.6 Major System Failure Procedures

Major System Failures are unpredictable both with respect to timing and the resulting implications. The System Operator shall establish procedures for determining when an incident on the System shall be considered a Major System Failure and also establish outline procedures for handling these Major System Failures as required under the Electricity Act 2015, Part VII.

In certain circumstances, the System Operator may require an Emergency Operation Centre to be established to coordinate the response to a Major System Failure and to avoid placing further stress on existing System Operator and User operational control arrangements.

The System Operator shall inform Generators promptly that an Emergency Operation Centre is to be established and request all relevant Generators to implement System Incident Communications Procedures. The System Operator shall specify the responsibilities and functions of the Emergency operations Centre and the relationship with existing operational and control arrangements.

The Emergency Operation Centre established in accordance with the System Operator s instructions shall have any responsibility for the Operation of the Transmission System and shall be the focal point for communication and the dissemination of information between the System Operator and senior management representatives of relevant Users, the OUR and Government.

During a Major System Failure, normal communication channels for operational control communication between the System Operator and Users shall continue to be used.

The System Operator shall decide when conditions no longer justify the need to use the Emergency Operation Centre and shall inform all relevant Generators within 30 minutes by facsimile or other agreed electronic means accordingly.

TC 12.7 Major System Failure Communications

The System Operator and Generators shall ensure that there are suitable communication channels available and established protocols, including the responsibilities of senior members of staff, to facilitate the co-ordination of activities after a Major System Failure.

The System Operator and all Users shall maintain lists of telephone contact numbers at which, or through which, senior management representatives nominated for this purpose and who are fully authorized to make binding decisions on behalf of the System Operator or the relevant User can be contacted day or night.

The lists of telephone contact numbers shall be provided in writing prior to the time that a Generator connects to the Transmission System and must be up-dated and circulated to all relevant Parties, in writing, whenever the information changes. Notifications and responses shall be made normally by telephone but must be confirmed in writing within 30 minutes.

All Major System Failure communications between the Senior Management representatives of the relevant Parties with regard to the System Operator’s role in the Major System Failure shall be made via the Emergency Operation Centre if such a Centre has been established.

TC 12.7.1 System Alerts/Warnings

In the event of Major System Failures, such as Total System Shutdown or a System separation, the System Operator shall issue promptly an alert warning to all Users.

The form of the Alert Warning will be:

a. This is an Alert timed at hours;

b. There is a (Major System Failure) at ……. (place);

c. A System normalization Procedure is being implemented;

d. Standby for further instructions.

TC 13 INCIDENT INFORMATION SUPPLY

TC 13.1 Introduction

This section of the Code requires the System Operator and Generators to issue notices of all Incidents on their respective Systems that have or may have implications for the Transmission System or a User's System.

The System Operator shall determine that if Incident should be classified as a Major System Failure in accordance with section VII of the Electricity Act 2015.

Sub-section TC 12.7 set out the procedures for reporting and subsequent assessment of Major System Failures.

Where a Significant Incident has been declared the System Operator may request an investigation be carried out.

The composition of such an investigation panel shall be appropriate to the Incident to be investigated.

Where there has been a series of Significant Incidents (that is to say, where a Significant Incident has caused or exacerbated another Significant Incident) the System Operator may determine that the investigation should include some or all of those Significant Incidents.

Any investigation under sub-section TC 13 is separate from any inquiry which may be carried out under legal or statutory requirements.

Sub-section TC 13.4. requires the System Operator or a Generator to prepare:

a preliminary written Incident report within 24 hours of the Incident;

For a Major System Failure, a written report is required within 30 days of the Incident.

In addition, sub-section TC 13 contains requirements governing the content of Major System Failure reports, the circulation of these reports, and their subsequent assessment and review by the Code Review Panel.

TC 13.2 Objective

The objectives of section TC 13 are:

a. to specify the obligations of the System Operator and Generators regarding the issue of notices of Incidents on their respective Systems;

b. to ensure notices of Incidents provide sufficient detail to allow recipients of such notices to fully assess the likely implications and risks and take the necessary actions required to maintain the security and stability of the Transmission System or a Generator' s System;

c. to specify the arrangements for reporting Incidents that the System Operator has determined to be a Major System Failure; and

d. to provide for the review of all Major System Failure reports by the Code Review Panel to assess the effectiveness of policies adopted in accordance with this Dispatch Code and the other Grid Codes.

TC 13.3 Notification of Incidents

The System Operator and Generators shall issue notifications of Incidents on their respective Systems that have had or may have implications for the Transmission or Distribution System in the case of the Generator, or a Generator's System in the case of both the System Operator and Generator notifications. Where information is requested in writing throughout this Code, facsimile transmission or other electronic means as agreed with System Operator in writing may be used.

Without limiting the requirements of this Code, Incident notifications shall be issued for the following, subject to sub-section TC 13.3.1; where Plant has been Operated in excess of its rated capability and presented a hazard to Persons;

The activation of any alarm or indication of any abnormal operating condition; adverse weather conditions being experienced; breakdown of, faults on or temporary changes in the capabilities of Plant; breakdown of or faults on control, communication and Metering equipment; and increased risk of inadvertent Operation of protection devices, relays or Equipment.

TC 13.3.1 Incidents on the Transmission System

In the case of an Incident on the Transmission System, which has had or may have an operational Effect on a Generator's System, the System Operator shall notify the Generator who's Generation System will be, is, or has been affected.

TC 13.3.2 Incidents on a Generator's System

In the case of an Incident on a Generator's System, which has had or may have an Operational Effect on the Transmission System, the Generator shall notify the

System Operator. Following notification by the Generator, the System Operator shall notify any other Users whose systems will be, or have been affected.

TC 13.3.3 Form of notification

Incident notifications must be issued promptly. Notifications and responses to notifications may be made by telephone or the mass media, but shall be confirmed in writing within one (1) hour or as soon as it is practical to do so.

The appropriate party shall issue a notification (and any response to questions asked) of any Incident that has arisen independently of any other Incident.

The notification shall;

a. be of the Incident (but is not required to state its cause);

b. be of sufficient detail to enable the recipient of the notification to reasonably consider and assess the implications, and risks arising; and include the name of the individual reporting the Incident on behalf of the Grid Operator or the User.

The recipient of a notification may ask questions to clarify the notification and the provider of the notification shall, insofar as they are able, answer any questions raised.

An Incident notification shall be given as soon after the Incident as possible to allow the recipient to consider and assess the implications and risks arising from the Incident.

TC 13.4 Major System Failure Reporting

The System Operator may determine that an Incident reported by it or a Generator shall be classified as a Major System Failure.

The System Operator shall promptly notify all potentially affected Users by telephone or other media that such a determination has been made and that procedures governing Major System Failure reporting are to be followed. The System Operator shall confirm such notice within 30 minutes by facsimile or other electronic means. All affected Users shall acknowledge receipt of the notification within 15 minutes of receipt by facsimile or other electronic means.

TC 13.4.1 Timing of Major System Failure reporting

Preliminary report

The System Operator or must produce a preliminary written Incident report within 24 hours.

Full report

The System Operator or must produce a full written Major System Failure report within 30 business days a Major System Failure.

A Generator shall produce a Major System Failure Report within 20 days of a Major System Failure caused by its Generation System. This is to facilitate the System Operator preparing its Major System Failure Report within 30 days for submission to the Office and the Minister as required under the Electricity Act 2015.

Written reporting of Major System Failures by the System Operator to Generators.

In the case of a Major System Failure reported by the System Operator to a Generator , the System Operator shall provide a full written Major System Failure report to the OUR.

Upon the request of the System Operator, a Generator shall provide a report of the Incident to the System Operator. The System Operator may use the information contained from an Incident report from a Generator therein in preparing the written report.

Written reporting of Major System Failures by Generators to the System Operator.

In the case of an Incident, that has been reported by a Generator to the System Operator and determined by the System Operator as a major System Failure, the Generator shall provide a full written Major System Failure report to the System Operator. The System Operator shall not pass this report to other affected Users but may use the information contained therein in preparing a Major System Failure report to the OUR.

TC 13.5 Form of Significant Incident report

A full Major System Failure report prepared by the System Operator shall be sent to the Minister and the OUR. The full Major System Failure report shall contain confirmation of the Major System Failure notification together with full details relating to the Major System Failure.

The Major System Failure report should, as a minimum, contain the following:

a. date and time of Significant Incident;

b. location;

c. Apparatus involved;

d. brief description of the Major System Failure;

e. causes of the Failure;

f. details of any Demand Control undertaken;

g. effect on other System Users including where appropriate:- duration of Incident and estimated date and time of return to normal service;

h. effect on generation including generation interrupted; frequency response achieved; MVAr performance achieved; and estimated date and time of return to normal service;

i. measures and procedures taken to restore the System;

j. measures that should be taken to avoid a recurrence of the failure; and

k. an assessment of the cost associated with the failure.

The above list is not intended to be exhaustive to this section TC 13 of the Code.

TC 14 COMMUNICATIONS AND CONTROL

In order to ensure control of the Transmission System, telecommunications between Users and the System Operator must be established if required by the System Operator.

Control Telephony is the method by which a User Responsible Engineer/Operator and the System Operator s Control Engineers speak to one another for the purposes of control of the Transmission System in both normal and emergency operating conditions. At any Interconnection Point where the User telephony equipment is not capable of providing the required facilities or is otherwise incompatible with the System Operator s control telephony, the User shall install appropriate telephony equipment to the specification of the System Operator. Details of and relating to the control telephony required shall be set out in the Interconnection Agreement.

The System Operator shall provide Supervisory Control and Data Acquisition (SCADA) outstation interface equipment. The User shall provide such voltage, current, frequency, Active Power and Reactive Power measurement outputs and plant status indications and alarms to the System Operator SCADA outstation interface equipment as required by the System Operator in accordance with the terms of the Interconnection Agreement. The manner in which information is required to be presented to the outstation equipment is set out in section GC 5 of the Generation Code.

TC 15 NUMBERING AND NOMENCLATURE OF HV APPARATUS

TC 15.1 Introduction

This section sets out the requirements that:

a. Transmission Apparatus on Users’ Sites ; and

b. User Apparatus on Transmission Sites

shall have numbering and nomenclature in accordance with the System used from time to time by the System Operator.

The numbering and nomenclature of each item of Apparatus shall be included in the Operation Diagram prepared for each Interconnection Site. Further provisions on Operation Diagrams are contained in TC Appendix B.

The term Apparatus includes any associated SF6 Gas Equipment.

TC 15.2 Objective

The overall objective is to ensure, so far as possible, the safe and effective Operation of the Total System and to reduce the risk of human error by requiring, in certain circumstances, that the numbering and nomenclature of User's Apparatus shall be in accordance with the System used from time to time by the System Operator.

TC 15.3 Transmission Apparatus on Users' Sites

Transmission Apparatus on Users' Sites shall have numbering and nomenclature in accordance with the System used from time to time by the System Operator.

When the System Operator is to install its Apparatus on a User's Site, the System Operator shall notify the relevant User of the numbering and nomenclature to be adopted for that Apparatus at least eight months prior to proposed installation.

The notification shall be made in writing to the relevant User and shall consist of both a proposed Operation Diagram incorporating the proposed Transmission Apparatus to be installed, its proposed numbering and nomenclature, and the date of its proposed installation.

The relevant User shall respond in writing to the System Operator within one month of the receipt of the notification, confirming receipt and confirming either that any other Apparatus of the relevant User on such User Site does not have numbering and/ or nomenclature which could be confused with that proposed by the System Operator, or, to the extent that it does, that the relevant other numbering and/ or nomenclature shall be changed before installation of the Transmission Apparatus.

The relevant User shall not install, or permit the installation of, any Apparatus on such User Site which has numbering and/ or nomenclature which could be confused with Transmission Apparatus which the System Operator has advised the User to be installed on that User Site or is already on that User Site.

TC 15.4 User Apparatus on Transmission Sites

User Apparatus on Transmission Sites shall have numbering and nomenclature in accordance with the System used from time to time by the System Operator.

When a User is to install its Apparatus on a Transmission Site, or it wishes to replace existing Apparatus on a Transmission Site and it wishes to adopt new numbering and nomenclature for such Apparatus, the User shall notify the System Operator of the details of the Apparatus and the proposed numbering and nomenclature to be adopted for that Apparatus, at least eight months prior to proposed installation.

The notification shall be made in writing to the System Operator and shall consist of both a proposed Operation Diagram incorporating the proposed new Apparatus of the User to be installed, its proposed numbering and nomenclature, and the date of its proposed installation.

The System Operator shall respond in writing to the User within one month of the receipt of the notification stating whether or not the System Operator accepts the User's proposed numbering and nomenclature and, if they are not acceptable, it shall give details of the numbering and nomenclature which the User shall adopt for that Apparatus.

TC 15.5 Changes

Where the System Operator in its reasonable opinion has decided that it needs to change the existing numbering or nomenclature of Transmission Apparatus on a User Site or of User Apparatus on a Transmission Site.

The provisions of this sub-section TC 15.5 shall apply to such change of numbering or nomenclature of Transmission Apparatus with any necessary amendments to those provisions to reflect that only a change is being made; and

in the case of a change in the numbering or nomenclature of User Apparatus on a Transmission Site, the System Operator shall notify the User of the numbering and/or nomenclature the User shall adopt for that Apparatus (the notification to be in a form similar to that envisaged under TOC10.4) at least eight months prior to the change being needed and the User shall respond in writing to the System Operator within one month of the receipt of the notification, confirming receipt.

In either case the notification shall indicate the reason for the proposed change.

Users shall be provided upon request with details of the System Operator's then current numbering and nomenclature System in order to assist them in planning the numbering and nomenclature for their Apparatus on Transmission Sites.

When a User installs Apparatus in accordance with TC 15, the User shall be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature.

Where a User is required by TC 15 to change the numbering and/ or nomenclature of Apparatus, the User shall be responsible for the provision and erection of clear and unambiguous labelling by the required date.

When the System Operator installs Apparatus which is the subject of TC 15, the System Operator shall be responsible for the provision and erection of a clear and unambiguous labelling showing the numbering and nomenclature. Where the System Operator changes the numbering and/or nomenclature of Apparatus which is the subject of this section TC 15, the System Operator shall be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature by the required date.

TC 16 TESTING, MONITORING AND INVESTIGATION

TC 16.1 Introduction

Section TC 16 sets out the authorization required and the procedures to be followed by the System Operator, and Users wishing to conduct operational Tests or Site investigations involving Plant and Apparatus connected to or part of the Transmission System.

The Code stipulates that prior authorization from the System Operator is required before conducting operational Tests or Site Investigations.

TC 16.2 Objective

The objectives are to ensure that operational Tests and Site Investigations;

a. are authorized by the System Operator and are carried out in accordance with appropriate procedures;

b. are carried out in a coordinated manner to avoid unnecessary risk or damage to Plant and to minimise costs to the System Operator and affected Users;

c. do not threaten the safety of personnel or the general public;

d. do not threaten the security or stability of the Transmission System;

e. and are properly evaluated on completion and, where appropriate, subject to predefined reporting arrangements.

f. A further objective is to allow sufficient tests to be conducted to enable predictive fault finding.

TC 16.3 Categories of tests

This sub-section covers the following categories of test:

a. operational tests to commission or test the compliance of Generating Units with the requirements of a Power Purchase Agreement or for other purposes specified in the Generation Code.

b. Site Investigation tests in relation to Plant, Apparatus and operational procedures at Generator and User sites.

c. Other tests required, in certain circumstances, whether by means of a formal test or verification by inspection, to ascertain whether Operating Parameters and/or the Interconnection Code are being complied with in respect of the User s Plant and Apparatus.

TC 16.4 Authorization and Test Procedures

Prior authorization from the System Operator is required before conducting an operational Test, Site Investigation or other test.

Users seeking to conduct an operational Test or Site Investigation shall submit a Test Request to the System Operator giving at least 8 weeks minimum notice before the date of the proposed test. A Test Request shall include a detailed test proposal including:

a. a brief description of the proposed test;

b. the preferred time or times for the test and the potential duration;

c. the reason for the proposed test indicating whether the test is required for compliance with Licence conditions, statutory regulations or Safety Rules. This shall assist in determining the priority to be given to the test;

d. an indication of any potential adverse effects if the Test is cancelled at short notice or delayed; and

e. an indication of any Dispatch Instructions or operational switching required to facilitate the test.

The System Operator shall consider the following factors when evaluating a Test Request:

a. The impact of the requested test on Transmission System stability and security;

b. the impact of the requested test on Transmission System economics;

c. the impact of the requested test on other Users; and

d. the effect of the requested test on the continuity and quality of electricity Supply.

If the System Operator approves a Test Request, it shall inform the test proposer accordingly in writing.

If the System Operator requests additional information from the test proposer to evaluate the impact of a Test Request the System Operator shall stipulate the time within which the information shall be provided. If the information is not provided in the timescale indicated by System Operator the Test Request shall automatically lapse.

If the System Operator does not approve a Test Request, it shall set out its reasons for rejecting the application and consult with the Test proposer on any changes to the Test proposal required to secure approval for the Test. The Test proposer may update a Test proposal in accordance with guidance provided by the System Operator and submit a revised Test Request.

The System Operator shall not withhold approval of a Test Request unless it considers it has reasonable grounds for doing so. If a User is not satisfied that a Test request was rejected on reasonable grounds it can refer the matter to the OUR for determination.

The System Operator shall not disclose any information received as part of a Test Request application without the consent of the User who submitted the Test Request if it reasonably believes the information to be commercially sensitive or otherwise potentially sensitive.

TC 16.5 Test Panel

If a Test Request is approved, the System Operator shall decide if a Test Panel is required. If the System Operator decides that a Test Panel is required, the test proposer shall convene a Test Panel, subject to the approval of the System Operator... The number of Test Panel members shall be kept to the minimum number of persons compatible with affected User representation.

The Chairman of a Test Panel shall be appointed by the System Operator. The System Operator and all directly affected Users shall be represented on the Test Panel.

The duties and responsibilities of the Test Panel are as follows:

a. to prepare a detailed programme for the conduct of the test, including the start and end date of the test, and any Dispatch requirements and operational switching required to facilitate the test;

b. to identify the detailed management requirements of the test;

c. to ensure that all affected Parties are properly informed of and have access to all relevant information;

d. to schedule the resources required to conduct the test; and

e. to prepare a Test Document that shall include all the elements listed above.

The Test Document shall be copied to all members of the Test Panel at least 2 weeks before the start date of the test. Members of the Test Panel may provide comments on the Test Document to the Chairman of the Test Panel no later than 1 week before the scheduled start date of the Test.

The test shall proceed only on the condition that the Test Panel has approved the Test Document. If a member of the Test Panel is not satisfied with the test proceeding and they have fully discussed the issues within the Test Panel, they may make representation to the OUR.

The System Operator shall not disclose information provided to a Test Panel without the consent of the person who submitted the information if it reasonably believes the information to be commercially sensitive or otherwise potentially sensitive.

TC 16.6 Post Test Reporting Requirements

At the conclusion of an operational Test or Site Investigation the test proposer shall prepare a written report on the test that shall be available within 4 weeks of the conclusion of the operational Test. The report shall be copied to the System Operator and the OUR.

The Test Report shall not be submitted to any other person who is not a representative of the System Operator or the test proposer unless the System Operator and the test proposer having reasonably considered the confidentiality issues arising, and shall have unanimously approved such submission.

The Test Report shall include a detailed description of the completed Test, the Plant or Apparatus to which the Test relates, together with the results, conclusions and recommendations as they relate to the Test proposer, System Operator and all Users operationally affected by the Test, where applicable.

The Test Panel shall be disbanded after the final test report has been approved.

TC 16.7 Operational tests

The System Operator shall cooperate with the implementation of all operational Tests.

Where the System Operator considers the impact of an operational Test to be significantly greater than originally estimated, the System Operator may at any time contact the Test proposer to discuss a revised Test procedure or schedule.

The System Operator shall, where it considers it necessary to do so, cancel, interrupter postpone an operational Test at any time.

If the Test proposer wishes to cancel an operational Test before commencement of the Test or during the Test, the Test proposer must notify the System Operator immediately and the notice must be confirmed in writing within 1 hour by facsimile or other electronic means.

TC 16.8 Operational Tests Required by the System Operator

The System Operator may from time to time need to conduct operational Tests in order to maintain and develop operational procedures, to train staff, and to acquire information in respect of Transmission System behaviour under abnormal System conditions.

The System Operator shall endeavor to keep the frequency of occurrence, scope, and impact of operational Tests to the minimum necessary.

Where the System Operator intends to carry out an operational Test and in the System Operator s reasonable opinion, such a test will or may have an operational Effect on a User s System, the System Operator shall give [8] weeks' notice and provide sufficient information to the affected Users to enable the affected Users to assess any risks to their Systems.

The information provided by System Operator shall include;

a. a brief description of the operational Test;

b. the probable effects of the operational Test; and

c. the scheduled time and duration of the operational Test.

Affected Users may contact the System Operator to request additional time or information to consider the impact of the operational Test on their Systems and shall respond to the System Operator within 2 weeks of receipt of the System Operator s notice of the test.

TC 16.9 Operational Tests Required by Users

Operation of Users Plant and Apparatus in accordance with Prudent Utility Practice requires testing to maintain and develop operational procedures, develop and measure Plant performance, comply with statutory or other industry obligations and contracts, and to train staff.

Each User shall endeavor to limit the frequency of occurrence of operational Tests and to limit the effects of such operational Tests on the Transmission System.

Users shall submit a Test Request to the System Operator in accordance with the requirements of sub-section TC 16.5.

TC 16.10 Operational Tests of Generating Units

The procedure to be adopted for the operational testing of Generating Units is set out in the Generation Code and summarized below.

The Generator shall provide to the System Operator a timetable and list of all tests to be performed on the Generating Units, and such tests shall be subject to approval by the System Operator. The System Operator shall be given five (5) days' notice of any testing and shall reserve the right to have a representative present during any such tests.

Testing and monitoring of Generating Units is generally performed for the purpose of determining available Capacity and, if relevant, operating characteristics in accordance with the commercial and technical conditions of Power Purchase Agreements.

Prior to the Synchronization of each new Generating Unit, the Generator shall carry out a number of tests as set out in the Generation Code. These tests cover such aspects as Automatic Voltage Regulator Setting, governor control checks, open and short circuit tests etc.

After the Pre-Synchronization tests as defined in TC 16.10.4 and prior to the commissioning date, and under such subsequent conditions as defined by Power Purchase Agreements, Generator shall carry out the following tests:

a. Dependable Capacity;

b. reliability run;

c. automatic voltage regulator (AVR) Droop;

d. governor Operation;

e. reactive Capacity;

f. short-term Load Capability;

g. response of Unit to Step Load Changes;

h. full Load Rejection; and

i. thermal Performance Tests

Fully detailed requirements for Generator Testing are set out in section GC 12 Testing and Monitoring of the Generation Code.

TC 16.11 Other operational Tests

Any operational Test proposal accompanying a Test Request shall indicate whether Dispatch Instructions and operational switching instructions are required to facilitate the test.

The System Operator shall, subject to any amendments it may require to be made, incorporate the Dispatch Instructions and operational switching instructions required to facilitate the test.

The System Operator shall issue Dispatch Instructions for operational Tests in accordance with the procedures set out in the Generation Code.

In accordance with the Generation Code the Generator shall provide to the System Operator a timetable and list of all tests to be performed on the Generating Units, and such tests shall be subject to approval by the System Operator. The System

Operator shall be given five (5) days' notice of any testing and shall reserve the right to have a representative present during any such tests.

The System Operator shall inform other Users of the scheduled time and nature of the test, if in the opinion of System Operator those Users will or may be affected by the test.

The operational Test shall proceed in accordance with normal operational practices but with particularly close communication between the System control engineer and the person responsible for the execution of the Test. Where the operational Test is complex or time consuming, the System Operator shall provide additional support at the System Control Centre, if necessary.

TC 16.12 Site Investigation Tests

The System Operator may, if it reasonably considers that there may be an issue of non-compliance with an agreement by the User, carry out a Site Investigation to acquire or verify information relevant to Users Plant and/or Apparatus design, Operation or Interconnection requirements under the Transmission Code, Interconnection Agreements and other agreements between Users and the System Operator.

The System Operator may, having given reasonable notice, send a representative or agent to a User s site in order to investigate any equipment or operational procedure applicable to the User site insofar as the condition of that equipment or operational procedure is relevant to compliance with a the Transmission Code, an Interconnection Agreement, or other relevant agreements.

TC 16.13 Other Tests

The System Operator can, at any time, request a test. Where an Agreement exists (with appropriate test procedures) these shall form the basis of the test.

Testing, including tests carried out under any relevant agreement may involve attendance by the System Operator or their representatives at User sites in order to carry out or observe such tests.

Where required, a test shall be carried out in accordance with Dispatch Instructions and operational switching instructions issued by the System Operator or by such alternative procedures as is required or permitted by the Transmission Code.

Where a test is required at short notice, the System Operator shall use reasonable endeavors to accommodate the test in the requested timescale provided that in the System Operator s reasonable opinion the test would not compromise the security and stability of the Total System, or pose a risk to the safe and secure Operation of Plant, or compromise the safety of related personnel and the general public.

TC 17 TRANSMISSION METERING

TC 17.1 Purpose

This section of the Transmission Code sets out the way in which power and energy flows shall be measured at an operational Interface.

The Metering Code is required to establish the requirements for metering the Active and Reactive Energy and Demand from its entry to the Transmission System to its exit to the Distribution System and Large Customers.

The Code also sets out appropriate procedures for meter reading; and

Ensures that procedures are in place to manage disputed readings.

TC 17.2 Scope

This section applies to:

a. The System Operator

b. Large Customers

c. Generators.

The requirements for the metering of Generators are set out in the Generation Code. An outline of the requirements is set out in sub-section TC 17.3.

For Large Customers the metering requirements follow those of a User connected to the Distribution System as set out in the Distribution Code. An outline of these requirements is set out in sub-section TC 17.6.

TC 17.3 Metering Requirements - Generators

Adequate Metering Systems consistent with the technical specifications of this clause shall be installed by the Generator. The Metering System shall comprise a Primary and Backup Metering System and shall be designed, financed and installed by the Generator. The System Operator shall own and maintain the Primary Metering System while the Generator shall own and maintain the Backup Metering System.

TC 17.3.1 Overall Accuracy

The overall accuracy of Generator metering is to be designed to give a tolerance of ±0.5% on an ongoing basis.

TC 17.3.2 Relevant Metering Policies, Standards and Specifications

Both Primary and Backup Metering Systems shall be installed to accumulate the outputs and/or inputs at the High Voltage side bushing of the Generating Unit step up transformer.

The System Operator shall own and maintain the Primary Metering System while the Generator shall own and maintain the Backup Metering System.

Each meter shall have its own Current Transformer (CT) and Voltage Transformer (VT) and necessary independent systems to function effectively.

Instrument transformers shall conform to ANSI Standard C12.11 and C57.14 Class 03 and shall have sufficient capacity to handle the attached equipment. The ANSI standards refer to the physical characteristics of meters and the procedures and practices related to type and pattern approval. The detailed use of these standards in the testing of meters are set out in OUR Document ELE 2005/07 Electricity Meter Testing in Jamaica - Protocol on Administrative Meter Testing.

The Current Transformers secondary winding used for metering purposes shall supply only the metering equipment and associated systems. Notwithstanding the foregoing each Current Transformer may have other secondary windings that may be used for purposes other than metering.

Potential transformers’ secondary windings may be used for metering and other purposes provided that the total loading does not exceed one half burden of the rating of the transformer.

TC 17.4 Parameters for Meter Reading

The Generator shall provide and install meters equal or equivalent to the specification provided by the System Operator and shall make a continuous recording on appropriate magnetic media or equivalent of the Net Energy Output of the Generating Unit(s).

The parameters to be metered shall be subject to the Interconnection Agreement between the Generator and the System Operator, and may consist of but are not limited to any or all of the following parameters:

a. Active Energy (Wh) OUT;

b. Active Energy (Wh) IN;

c. Reactive Energy (VARh) First Quadrant;

d. Reactive Energy (VARh) Fourth Quadrant;

e. Active Power Demand (W) OUT;

f. Active Power Demand (W) IN;

g. Reactive Power Demand (VAR) First Quadrant; and

h. Reactive Power Demand (VAR) Fourth Quadrant.

All units shall be expressed at appropriate multiples determined by the maximum expected demand.

TC 17.5 Frequency of Reading

The Demand Interval shall be fifteen (15) minutes and shall be set to start at the beginning of the hour. Demand shall be calculated by averaging the respective parameters over the stated Demand Interval.

The System Operator shall read the appropriate meters to prevent clock drift, the clocks shall be checked and reset as agreed by the Parties. If readings are obtained remotely, copies of the data produced by the computer which initiates the reading protocol can be made and provided to the Generator if requested.

TC 17.6 Metering Requirements - Large Customers

TC 17.6.1 Overall Accuracy

The overall accuracy of the metering for revenue purposes is to be designed to give a tolerance of ± 1% when tested in the laboratory and ±2% when tested in the field.

TC 17.6.2 Relevant Metering Policies, Standards and Specifications

The meters, and associated installations, used on the System Operator's Transmission System shall comply with the following documents which are identified in Transmission in sub-section TC 7.6.2.

a. Licensee Engineering Instruction 4.7

b. OUR Document ELE 2005/07 Electricity Meter Testing in Jamaica - Protocol on Administrative.

c. Meter Facilities Policy as set out in Licensee Engineering Bulletin TSD 007/3.

The meters shall be designed, constructed and operated to comply with the latest revision of the relevant ANSI standards or international equivalents in particular:

a. ANSI C12.1 2008 The Electric Meters code for Electricity Metering;

b. ANSI C12:10 2004 Physical aspects of watt-hour meters - safety standard; and

c. ANSI C12:20 2002 Electricity meters 0.2 and 0.5 accuracy Classes.

TC 17.7 Requirement for Metering

All Interconnection Points to the Transmission System shall have appropriate metering in accordance with this Transmission Metering Code. The position of the metering shall be set out in the Interconnection Agreement between the System Operator and the Large Customer.

TC 17.8 Metering Responsibility

The System Operator shall ensure that all Interconnection Points with Large Customers are metered in accordance with this Code.

It is the responsibility of Large Customers and Generators to cooperate with the System Operator in the execution of its responsibilities under this Code and, where applicable, under the Generation Code.

The costs for installation and replacement of meters shall be outlined in the User's Interconnection Agreement or the Generator s Power Purchase Agreement or Standard Offer Contract.

TC 17.9 Metering Equipment

The metering equipment shall consist of:

a. Revenue Meters;

b. Current and Voltage Transformers where applicable;

c. all interconnecting cables, wires and associated devices, seals and protection; and

d. all Equipment associated with Advanced Metering Infrastructure.

TC 17.9.1 Revenue Meters

The Revenue Meter shall have the appropriate rating for the Interconnection requirements to be supplied and shall conform to the terms of the Interconnection Agreement between the System Operator and the Large Customer.

Meters shall have an accuracy in accordance with ANSI class 0.5 or international equivalent.

At the System Operator s discretion Advanced Metering Infrastructure may be installed at some Customers Sites. This metering infrastructure enables two way communication with the metering systems. These devices shall comply with the specifications in TC 19.2.2. The accuracy shall be equivalent to ANSI Class 0.5.

The relevant metered parameters, as required by the System Operator for billing purposes, shall be stored cumulatively on the meter and shall be able to be accessed by the Large Customer.

Where required these parameters may include any or all of the following depending on the Interconnection and the tariff schedule:

a. KW Hours (delivered and received);

b. KVAr Hours (delivered and received);

c. KVA Hours (delivered and received);

d. Ampere Squared Hours;

e. Volt Squared Hours;

f. Maximum Demand (15 minute period); and

g. Power Factor.

The above parameters shall be measurable over intervals from 1 minute to 60 minutes.

TC 17.9.2 Voltage and Current Transformers

All Voltage and Current Transformers shall comply with IEC Standards or their equivalents and shall have an accuracy class of 0.5.

The burden in each phase of Voltage and Current Transformers shall not exceed the specified burden of the said Transformers.

TC 17.10 Metering Points

TC 17.10.1 Whole Current Metering

The Metering Point should be as close as possible to the Interconnection Point.

TC 17.11 CT Metering

The Metering Point shall be at the position of the Current Transformers (CT) used for the metering System. This should be designed to be as close as possible to the Interconnection Point.

Current Transformers should be installed in a separate chamber and must be before the main switch (on the line side). They shall be housed in suitable metal enclosures, and be able to be secured.

Where the Interconnection Point is declared on the outgoing side of a high voltage circuit breaker the metering transformers may be accommodated in that circuit breaker unit.

Where appropriate the Metering Point should be at the same voltage as the Interconnection Point. Where the Metering Point is at a lower voltage than the

Interconnection Point then appropriate loss factors should be calculated to ensure any additional loss is appropriately accounted for.

TC 17.12 Meter Reading and Collection Systems

TC 17.12.1 Meter Reading and Recording Responsibility

It is the responsibility of the System Operator to ensure that meters are read in accordance with the requirements of overall Standard EOS7 in the System Operators Licence. Meter reading and recording shall be undertaken by a suitable authorized representative of the System Operator.

It is the responsibility of Generators and Large Customers to cooperate with the System Operator in the execution of its responsibilities under this Code.

The Customer shall be provided with access to its billing and consumption records on request.

TC 17.13 Approval of Meters

Only meters that have received pattern approval from the Bureau of Standards, Jamaica (BSJ) in accordance with "OUR ELE 2005/07 Electricity Meter Testing in Jamaica - Protocol on Administrative and Testing Procedures", may be used on the System Operator's Transmission System.

TC 17.14 Calibration and Sealing

TC 17.14.1 Calibration

All meters (new meters and repaired meters) rated above 12kVA shall be calibrated and the tolerance adjusted to ensure that it measures as close to zero tolerance as possible prior to field installation.

All meters rated above 12kVA shall be recalibrated every10 years unless they have a manufacturers guaranteed calibration period in which case this period shall be used.

All laboratory calibration shall be undertaken in laboratories accredited by the JANAAC.

TC 17.14.2 Traceability

The kilowatt hour standard used to calibrate electricity meters shall be traceable to the 'Systeme Internationale (SI)' at the 'Bureau Internationale des Pois et Measures'. This extends to the calibration of Equipment used to calibrate meters.

TC 17.14.3 Sealing

All meters shall be constructed to enable the meter unit to be sealed to prevent unauthorized access or interference with the Operation of the meter or the input terminals of the meter.

Seals applied after calibration shall be marked with the date that recalibration is required. All seals shall include marks that identify the authorized person that sealed the meter.

TC 17.15 Metering Disputes

TC 17.15.1 Meter Inaccuracy

If the metering System is found to be inaccurate more than the allowable error, and the System Operator and the User or Generator fail to agree upon an estimate for the correct reading within a reasonable time (as specified in the relevant PPA) of the Dispute being raised, then the matter may be referred for arbitration by either party in accordance with the relevant PPA.

TC 17.15.2 Meter Accuracy Check

The User has a right to request a meter accuracy check when they consider that the meter may be reading incorrectly, in accordance with the meter testing protocol.

Should a User request more than one accuracy check in a single calendar year and the accuracy is within ±2% then the System Operator may charge for the additional checks.

TC 17.16 Inspection and Testing

TC 17.16.1 Maintenance Policy

The System Operator shall put in place and implement policy for the inspection and testing and recalibration of all metering Equipment. This policy shall be in accordance with the procedures set out in sub-section TC 17.3.2 above.

TC 17.16.2 Maintenance Records

The System Operator shall keep all test results, maintenance programme records and sealing records.

TC 17.17 Generator Metering

The Generator shall abide by the conditions of the Generation Code that details the maintenance procedures to be applied in the case of Generator meters. The

Generation Code includes provisions on the use of Back-up meters when metering inaccuracies are suspected and on the resolution of metering disputes.

TC 18 TRANSMISSION SYSTEM DATA REGISTRATION

TC 18.1 Data to be Exchanged Between System Operator and User

The following Table provides details of the Schedules covering the data to be exchanged between the System Operator and the Users of the Transmission System

Schedule	Data Type	Description	User	Code section	Licensee Procedure
I	User System Data	Electrical parameters relating to Plant and Apparatus connected to the Transmission System	Licensee	TC 7.4.11 TC 5.3	EI 3.1 SOPP 4 SOPP 7 SOPP 9
II	Load Characteristics	The estimated parameters of loads in respect of, for Example, harmonic content, frequency response.	Licensee	TC 3.3 TC 3.17	
III	Demand profiles and Active Energy	Total demand and Active Energy taken from the Transmission System	Licensee	TC 3.3 TC 3.17 TC 5.3 DSC 3.3 GC 8.1	
VI	Fault Infeed	Information on Short Circuit contribution to the Transmission System.	Licensee DC GEN	TC 3.3 TC 3.17	

SCHEDULE I: USERS SYSTEM DATA

The data in this Schedule I is required from all Users interconnected directly to the Transmission System.

Data Description	Units	Code section	Licensee Instruction/Procedure
Operation Line Diagram **Single Line Diagram showing all existing and proposed** **equipment and Apparatus and Interconnections together with equipment rating**	Drawing	TC 5.3	SOPP 9
Site Responsibility Schedules	Schedule	TC 5.3	
Safety Coordinators	Text	DSC 12	
Reactive Compensation Equipment **For all reactive compensation equipment connected to the User System at [12kV] and above, other than Power Factor correction equipment associated directly with a Customer Plant, the following details** **Type of equipment (e.g. fixed or variable)** **Capacitive rating** **Inductive rating** **Operating range** **Details of any automatic control logic to enable operating characteristics to be determined** **Point of Interconnection to the User System in terms of electrical location and System voltage**	Text MVar Mvar Mvar Text and/or Diagrams Text	TC 5.3	SOPP 4 SOPP 7
Switchgear **For all switchgear (i.e. circuit breakers, switch** **disconnectors and isolators) on all circuits Directly** **Connected to the Interconnection Point including those at**	kV kV kA kA	TC 5.3	SOPP 7

Production Facilities **Rated voltage** **Operating voltage** **Rated short-circuit breaking current** **Single phase** **Three phase**			
Rated load breaking current **Single phase** **Three phase**	kA kA		

Data Description	**Units**	**Code Section**	**Licensee Instruction/Procedure**
HV Motor Drives **Following details are required for each HV motor drive** **connected to the User System** **Rated VA** **Rated Active Power** **Full Load Current** **Means of starting** **Starting Current** **Motor torque/speed characteristics** **Drive torque/speed characteristics** **Motor plus drive inertia constant**	MVA MW kA Text kA	TC 5.3	SOPP 7
User Protection Data **Following details relates only to protection equipment**	Text Text	TC 5.3	SOPP 7

which can trip, inter-trip or close any Interconnection Point circuit breaker or any System Operator circuit breaker **A full description including estimated settings, for all** **relays and Protection systems installed or to be installed on the User System** **A full description of any auto-reclose facilities installed on the User System, including type and time delays** **The most probable fault clearance time for electrical faults on any part of the User System Directly Connected to the Transmission System**	ms		
Transient Over-Voltage Assessment Data	Diagram	TC 5.3	SOPP 7
When requested by Licensee, each User is required to submit data with respect to the Interconnection Site as follows (undertaking insulation co-ordination studies) **Bus bar layout, including dimensions and geometry** **together with electrical parameters of any associated** **current transformers, voltage transformers, wall bushings, and support insulators** **Physical and electrical parameters of lines, cables,** **transformers, reactors and shunt compensator equipment** **Connected at that bus bar or by lines or cables to the** **bus bar (for the purpose of calculating surge impedances)** **Specification details of connected directly or by lines and cables to the bus bar including basic insulation levels** **Characteristics of over-voltage protection at the bus bar and at the termination of lines and cables connected at the bus bar**	Text Text Text		

SCHEDULE VI: FAULT INFEED DATA

The following information is required from each User who is connected to the Transmission System via an Interconnection Point where the User System contains Embedded Generating Unit(s) and/or motor loads. The data is required for the three following years

Data Description	Units	Update Time	Data Category

Short Circuit Infeed to Transmission System from User System at an Interconnection Point

Name of Interconnection Point: ______________________________

Symmetrical three-phase short circuit current infeed:

At instant of fault

After sub-transient fault current contribution has substantially decayed

Zero sequence source impedance values as seen from the Interconnection Point consistent with the maximum infeed above:

Resistance (R)

Reactance (X)

Positive sequence X/R ratio at instant of fault

SCHEDULE VIII: GENERATOR PLANNING PARAMETERS DATA

Generating Facility Name: ______________________________________

The following details are required from each Generating Facility directly connected, or to be directly connected, to the Transmission System and/or an existing, or proposed, Embedded Generating Facility. The data shall be supplied for the following 3 years.

The data in the following table shall be supplied for each generating unit.

Data Description	Units	Update Time	Data Category
9. Generator Performance Chart at stator terminals	Chart		
11. Short circuit ratio			
13. Rated field current at Rated MW and MVAr output and at rated terminal voltage	A		
14. Field current open circuit saturation curve as derived from appropriate manufacture's test certificate			
- 120% rated terminal voltage	A		
- 110% rated terminal voltage	A		
- 100% rated terminal voltage	A		
- 90% rated terminal voltage	A		
- 80% rated terminal voltage	A		
- 70% rated terminal voltage	A		
- 60% rated terminal voltage	A		
- 50% rated terminal voltage	A		

	Data Description	Units	Update Time	Data Category
	Generator Transformer			TC 7.5
1	Rated Apparent Power	MVA		

2	Rated voltage ratio	
3	Winding arrangement	
4	Vector group	
5	Positive sequence resistance	
	@ maximum tap	% on MVA
	@ minimum tap	% on MVA
	@ nominal tap	% on MVA
6	Positive sequence reactance	Positive sequence reactance
	@ maximum tap	% on MVA
	@ minimum tap	% on MVA
	@ nominal tap	% on MVA
7	Zero phase sequence reactance	% on MVA
8	Tap changer range	%
9	Tap changer step size	%
10	Tap changer type (i.e. on-load or off-load)	On/Off

	Data Description	Units	Update Time	Data Category
	Excitation Control System Parameters			TC 7.5
1	Exciter category (e.g. rotating or static)	Text		
	Details of Excitation System described in block diagram. Diagram showing transfer functions of individual elements (including Power System Stabilizer if fitted).			
5	Excitation System on-load positive ceiling voltage	V		
	Data Description	Units		

6	Excitation System no-load negative ceiling voltage	V
7	Power System Stabilizer fitted?	Yes/No
8	Details of over excitation limiter described in block diagram showing transfer functions of individual elements.	Diagram
9	Details of under excitation limiter described in block diagram showing transfer functions of individual elements	Diagram

APPENDIX A: SITE RESPONSIBILITY SCHEDULES

SITE RESPONSIBILITY SCHEDULES

At all Interconnection Sites the following Site Responsibility Schedules shall be drawn up using the pro-forma attached or with such variations as may be agreed between the System Operator and Users, and in the absence of agreement the pro-forma attached shall be used: i) Schedule of HV Apparatus ii) Schedule of Plant, LV Apparatus, services and supplies; iii) Schedule of telecommunications and measurements Apparatus.

Other than at Generating Unit and Power Station locations, the schedules referred to in (ii) and (iii) above may be combined.

Each Site Responsibility Schedule for an Interconnection Site shall be prepared by the System Operator in consultation with other Users at least 2 weeks prior to the Completion Date under the Interconnection Agreement for that Interconnection Site. Each User shall, in accordance with the timing requirements of the Interconnection Agreement, provide information to the System Operator to enable it to prepare the Site Responsibility Schedule.

Each Site Responsibility Schedule shall detail for each item of Plant and Apparatus;

1. Item of Equipment Using the agreed Numbering and Nomenclature in accordance with sub-section TC 15.
2. Equipment Owner identifies the party that owns the Equipment under common law;
3. Safety Rules identifies whether the System Operator s or User s Safety Rules shall be applied to the Equipment.
4. Operational Procedures identifies whether System Operator or Users personnel shall be responsible for operations on the Equipment. Note that if this is System Operator, it does not preclude the System Operator from authorizing Users personnel from acting on its behalf and vice versa.
5. Control Responsibility. This identifies whether the System Control used shall be the System Operators or the Users.
6. Maintenance Responsibility. This identifies whether the System Operator or the User is responsible for the inspection and maintenance of the Equipment.
7. Access and Security. This identifies whether the System Operator or the User shall be responsible for the establishment and maintenance of perimeter fencing and any manned access security for the protection of the public and to prevent malicious entry. Access to operational areas of the site shall be restricted to persons duly authorized in accordance with the prevailing Safety Rules.

The HV Apparatus Site Responsibility Schedule for each Interconnection Site must include lines and cables emanating from the Interconnection Site.

Every page of each Site Responsibility Schedule shall bear the date of issue and the issue number.

When a Site Responsibility Schedule is prepared it shall be sent by System Operator to the Users involved for confirmation of its accuracy.

The Site Responsibility Schedule shall then be signed on behalf of System Operator by the Manager responsible for the area in which the Interconnection Site is situated and on behalf of each User involved by its Responsible Manager, by way of written confirmation of its accuracy. Once signed, two copies shall be distributed by System Operator, not less than two weeks prior to its implementation date, to each User which is a party on the Site

Responsibility Schedule, accompanied by a note indicating the issue number and the date of implementation.

ATTACHMENT TO APPENDIX A: PRO FORMA FOR SITE RESPONSIBILITY SCHEDULE

COMPANY:

INTERCONNECTION SITE:

Item of Equipment	Equipment Owner	Safety Rules	Operational Procedures	Control Responsibility	Maintenance Responsibility	Access and Security	Comments

Signed on behalf of the System Operator Date ...

Signed on behalf of the User.

TC APPENDIX B: PROCEDURES RELATING TO OPERATION DIAGRAMS

Basic Principles

a. Where practicable, all the HV Apparatus on any Interconnection Site shall be shown on one Operation Diagram. Provided the clarity of the diagram is not impaired, the layout shall represent as closely as possible the geographical arrangement on the Interconnection Site.

b. Where more than one Operation Diagram is unavoidable, duplication of identical information on more than one Operation Diagram must be avoided.

c. The Operation Diagrams must show accurately the current status of the Apparatus, e.g. whether commissioned or decommissioned. Where decommissioned, the associated switch bay shall be labelled "spare bay".

d. Provision shall be made on the Operation Diagram for signifying approvals, together with provision for details of revisions and dates.

Apparatus to be shown on Ownership Diagrams.

1. Bus bars
2. Circuit Breakers
3. Disconnector (Isolator) and Switch Disconnectors (Switching Isolators)
4. Disconnectors (Isolators) - Automatic Facilities
5. Bypass Facilities
6. Earthing Switches
7. Maintenance Earths
8. Overhead Line Entries
9. Overhead Line Traps
10. Cable and Cable Sealing Ends
11. Generating Unit
12. Generator Transformers
13. Generating Unit Transformers, Station Transformers, including the lower voltage circuit- breakers

14. Synchronous Compensators
15. Static Var Compensators
16. Capacitors (including Harmonic Filters)
17. Series or Shunt Reactors
18. Grid Transformers
19. Tertiary Windings
20. Earthing and Auxiliary Transformers
21. Three Phase VTs
22. Single Phase VT & Phase Identity
23. High Accuracy VT and Phase Identity
24. Surge Arrestors/Diverters
25. Neutral Earthing Arrangements on HV Plant
26. Fault Throwing Devices
27. Quadrature Boosters
28. Arc Suppression Coils
29. Current Transformers (where separate Plant items)
30. Wall Bushings

Use of Approved Graphical Symbols

All graphical symbols to be used in the Operation Diagrams shall be approved by the System Operator.

TC APPENDIX C: TECHNICAL REQUIREMENTS FOR UNDER FREQUENCY RELAYS

Technical Requirements for Under Frequency Relays

The Interconnection Agreement shall specify the manner in which Demand at the User s Site, subject to Automatic Load Disconnection (separate from the System Operator s under frequency load shedding scheme), shall be actuated by Under-frequency Relays.

[1] Under Frequency Relays shall have a frequency setting range of 46.0 to 52.0Hz and be suitable for Operation from a nominal AC input of 63.5, 110 or 240V.

[2] The following general parameters on the requirements of approved Frequency Relays for automatic installations is given as an indication to the provisions that may be included in an Interconnection Agreement:

a. Frequency settings: 46-52Hz in steps of 0.01Hz;

b. Measurement period: Within a minimum selectable settings range of 3 to 7 cycles;

c. Operating time: Between 100 and 160ms dependent on measurement period setting;

d. Voltage lock-out: 20 to 90% of nominal voltage;

e. Facility stages: Four stages of frequency Operation;

f. Output contacts: Two output contacts per stage.

[3] The voltage supply to the Under Frequency Relays shall be derived from the Transmission System at the supply point concerned so that the frequency of the Under Frequency Relays input voltage is the same as that of the primary System. This requires either:

a. the use of a secure supply obtained from voltage transformers directly associated with the Transmission System interconnection transformer(s) concerned, the supply being obtained where necessary via a suitable automatic voltage selection scheme; or

b. the use of the substation 110V phase-to-neutral selected auxiliary supply, provided that this supply is always derived at the Interconnection Point concerned and is never derived from a standby generator or from another part of the User System.

[4] The tripping facility should be engineered 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. However, many failures would have the effect of reducing the amount of Demand under low frequency control. An overall reasonable minimum requirement for the dependability of the Demand shedding scheme is 96%, i.e. the average probability of failure of each Demand shedding point should be less than 4%. Thus the Demand under low Frequency control shall not be reduced by more than 4% due to relay failure.

Outages: Low frequency Demand shedding schemes shall be engineered such that the amount of Demand under control is as specified by the System Operator and is not reduced unacceptably during equipment outage or maintenance conditions.

APPENDIX D: FORM OF SIGNIFICANT INCIDENT REPORT

Form of Significant Incident Report

[1] Time and date of Significant Incident;

[2] Location;

[3] Pant or Apparatus directly involved (not merely affected by the Incident) including numbers and nomenclature;

[4] Description of Significant Incident including probable causes and any damage to Plant or Apparatus;

[5] Demand in MW and/or Generator output in MW interrupted and duration of interruption;

[6] Generator change in availability;

[7] Generator Frequency response (MW correction versus time achieved subsequent to the Significant Incident);

[8] Generator Mvar performance (change in output subsequent to the Significant Incident);

[9] Estimated or actual time and date of return to service and/or return to pre-Incident availability; and

[10] Any other relevant material.

Distribution Code

DC

DC 1 SCOPE

This Distribution Code sets out the procedures and principles governing the System Operator's relationship with all Users of the System Operator's Distribution System.

The Distribution Code shall be complied with by the System Operator and existing and potential Embedded Generators and Users connected to or seeking to connect to the System.

DC 2 GENERAL REQUIREMENTS

This Distribution Code contains the procedures to provide an adequate, safe and efficient service to all parts of Jamaica, taking into account a wide range of operational circumstances. It is however necessary to recognize that the Distribution Code cannot address every possible situation. Where such unforeseen situations occur the System Operator shall act as a reasonable and prudent operator in the pursuance of any or a combination of the following General Requirements to protect the safety of the public and employees;

a. the need to preserve the integrity of the System;

b. to prevent damage to the System;

c. compliance with conditions under its Licence;

d. compliance with the Act;

e. compliance with the Transmission Code.

Users shall provide such reasonable co-operation and assistance as the System Operator reasonably request in pursuance of the General Requirements.

DC 3 DISTRIBUTION PLANNING

DC 3.1 Purpose and Scope

Section 41-(1) of the Act provides that the Minister shall be responsible for planning the development of the system, which planning shall include:

a. The collection of data from electricity sector participants;

b. Consultations with the Office, the Single Buyer and other electricity sector participants; and

c. The conduct of Load forecast for approval by the Ministry.

This provision further requires that the planning process for transmission and distribution, considers the location of renewable and other generation sources, taking into account the potential for electrification of rural areas. The provision also requires that all Licence holders must comply with a request made by the Minister for information for the purposes of executing his planning responsibility under this section and failure to comply with a request under this sub-section, without reasonable cause, shall be an offence.

DC 3.2 Planning Process

DC 3.2.1 Introduction

The Distribution Code anticipates a three phase process for planning: long term, mid-term, and (short term) planning.

The Minister is responsible for long-term planning, leading the Integrated Resource Planning (IRP) process that establishes the policy guidelines for system development.

The System Operator is responsible for mid-term and operational planning.

DC 3.2.2 Long Term Planning

The Electricity Act Sections 4(a) and 7(1) contain new provisions that charge the Minister with responsibility for planning the development of the electricity system under the management of the System Operator, including integrated resource planning, the collection of data from electricity sector participants and the conduct of any relevant forecast. The Electricity Act section 7(2) requires that the planning process specifically consider the location of renewable and other generation sources, taking into account the potential for electrification of rural areas. Finally, Electricity Act section 7(3) mandates that all electricity sector participants must comply with a request from the Minister for information for the purposes of executing his planning responsibility.

The Ministry has informed OUR and electricity stakeholders that the Ministry will develop detailed procedures for development of an integrated resource plan, engaging key electricity sector stakeholders in a collaborative development process. The IRP process design is now underway, and will be published after the Grid Code publication in September 2016. It is anticipated that the long-term planning sections of the Generation, Transmission, and Distribution Codes may be revised soon after publication to fully support the Ministry's IRP development process, once finalized, and may be further revised in the future to adjust for changes in the IRP process.

The Distribution Code long-term planning requirements anticipate coordinated data collection system and ICT/software requirements among the Ministry, OUR, Licensee, and all IPPs required to support the IRP long term planning process, to assure that the Ministry receives the information required for its planning duties, and to minimize any inefficiencies.

The Ministry will lead the long term planning process, establishing the objectives and metrics of the IRP, and communicating those to all stakeholders, informing the public (including OUR and Licensee) of the status and outcome of the planning process.

It is anticipated that Transmission and Distribution Planning studies will be developed by Licensee and approved for use by the Ministry, with rate impacts analyzed by the OUR.

It is anticipated that Licensee will develop load forecasting projections and that the Ministry would develop assumptions and inputs for use in the load forecast, informing OUR of the load projections.

It is anticipated that the Ministry will be responsible for supply technologies modelled within the study and feasibility studies used to determine viable technologies are the responsibility of the Ministry. Licensee approves the integration of any technologies for operational purposes and contracting for resources; OUR will review rates impacts. The Ministry will approve contracting for third party resources to ensure consistency with Integrated Electricity Planning results.

Table 3-1 summarizes the anticipated IRP Inter-Agency Roles and Responsibilities.

Table 3-1: Inter-Agency Roles and Responsibilities

Responsibility	the Ministry	JPS	OUR (Rates)
Objectives and Metrics	Develop	Inform	Inform
Transmission & Distribution Planning Studies	Approve	Develop	Review for rates

Load Forecasting: Assumptions/Inputs supplied by the Ministry	Approve	Develop	Inform
Stakeholder Process: communication & policy	Develop	Inform	Inform
Supply Technologies and Feasibility Studies	Develop	Approve	Review for rates
Third Party Supply/Demand Contracts	Approve	Develop	Approve rates
Sales Forecasting	Approve	Develop	Approve rates
Energy Efficiency and Demand Programs	Develop	Inform	Approve rates
Policy Action Plans	Develop	Inform	Inform
Environmental Impacts – NEPA compliance management interface with Licensee	Develop	Inform	Inform

OUR will request the Grid Code Review Panel to prioritize development of detailed Long-Term Planning provisions consistent with the Ministry's planning process, once published.

DC 3.2.3 Mid-Term Planning

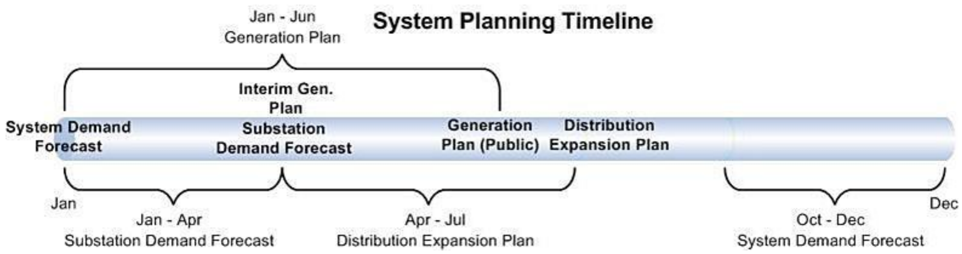
The System Operator is responsible for mid-term planning in compliance with the requirements of the Codes and the policy objectives set forth in an approved integrated resource plan.

DC 3.2.4 Operational Planning

The System Operator is responsible for operational planning in compliance with the requirements of the Codes and the policy objectives set forth in an approved integrated resource plan.

DC 3.3 Planning Timescales

The planning process above should operate on an annual planning cycle. The cycle commences with the gathering of information for the demand forecasting process in sub-section DC 3.7.2 at the beginning of Q3 (year n) and completes with the production of the Generation Least Cost Expansion Plan at the end of Q2 (year n+1) followed by the Distribution Expansion Plan a month later.



Interconnection related planning studies will be undertaken outside the above process, but new load information will be used to inform the demand forecasts. The timescales required to undertake the new interconnection studies necessary to plan the System vary depending on the driver for the studies and the ability to obtain consented routes.

For smaller interconnections the planning timescales are set and agreed with the OUR. These are included in the Distribution Interconnection Code section of this Distribution Code.

DC 3.4 Planning Principles

DC 3.4.1 Planning Criteria

Planning criteria are based on the requirement to comply with statutory requirements. Where no statutory requirements exist the criteria are based on international practices which would be expected of a reasonable and prudent System Operator.

The overriding principle in the planning of the System is the compliance with the Licence requirement for the System to “provide an adequate, safe and efficient service based on modern standards”.

The effective planning of the Distribution System requires consideration of a broad range of factors that can affect the network. These factors are identified in Appendix A to this Distribution Planning Code which serves as a representation of the broad scope of any System planning activity.

DC 3.4.2 Voltage Criteria

The System shall be designed to ensure that under normal and planned contingency conditions, voltages at all Interconnection Points and buses are to be within:

a. ± 5% of nominal voltage under normal conditions for Urban Area;

b. ±5% of nominal Voltage under normal conditions for Rural Areas'

   i. ±10% of nominal voltages under planned contingency conditions.

DC 3.4.3 Load Power Factor

The System will be planned for a normal load power factor of 0.90.

DC 3.4.4 Security of Supply

Jamaica does not have a prescriptive reliability standard that covers the Distribution System planning in terms of maximum restoration times for different load groups under different contingency considerations. This does not mean that security of supply is disregarded in the planning of the Distribution system. The Service Area Concept as described in section DC 3.5 will be used to set a base n-1 contingency level on a geographic basis and as a general planning guidance the overall network should be designed to ensure that 98% of Customers affected by faults can be restored within 24 hours as assessed on an annual basis.

DC 3.5 The Service Area Concept

The Distribution System has developed using predominantly radial HV feeders teed off of open ring Systems close to Transmission System substations. The design criteria utilizes a concept of Service Areas which are a network of substations and feeders defined by any subset of the following parameters:

a. Geography;

b. Feeder Connectivity;

c. Customer Type;

d. Serviceability of Load (Transformer Capacity, Acceptable Voltage);

e. Cost of Service Delivery.

The Service Areas will be defined by the System Operator.

In practical application the definition of Service Areas describes a section of (usually interconnected) Distribution System supplied from one or more HV bus bars. A Service Area is not necessarily a load Centre, however, situations may arise where this is the case.

The Service Area should be able to sustain itself under normal conditions, and during any single contingency event (i.e. loss of transformer, feeder, reclosers etc.).

The objectives of the Service Area concept are as follows:

a. ensure reliable service under normal and N-1 contingency conditions;

b. localize impact of N-1 contingency;

c. ensure restoration of supply to Customers after contingency in accordance with Overall Standards;

d. ensure structured approach to expansion of the distribution network;

e. maximize utilization of distribution plant and assets by feeder load management;

f. Group homogenous Customers to facilitate delivery of special service needs; and

g. Ensure network safety and security.

Service Area design criteria are as below:

a. Substation MVA capacity should be sufficient to satisfy load demand and to sustain a N-1 contingency situation;

b. service voltages for all feeders should be the same;

c. where economically feasible, each Service Area should have at least two (2) 3-phase Interconnection Points to adjacent Service Areas;

d. each feeder in Service Area must have at least one (1) 3-phase interconnection to a feeder supplied by another transformer;

e. feeder loadings must be maintained to sustain 100% load transfers within the Service Area after any contingency event; and

f. service area must be returned to normalcy after contingency.

Investment triggers for reinforcement expenditure to support the Service areas are as below:

a. violations of design criteria requirements for Service Area;

b. alternatives for load transfers do not exist;

c. Transformer loading exceed 105% of thermal rating under N-1 contingency conditions;

d. overhead line exceed 100% of thermal rating under normal or contingency conditions; and

e. violations of service voltage criteria under normal or N-1 conditions.

DC 3.6 Planning Studies

DC 3.6.1 General

The System Operator will undertake distribution planning studies as required to:

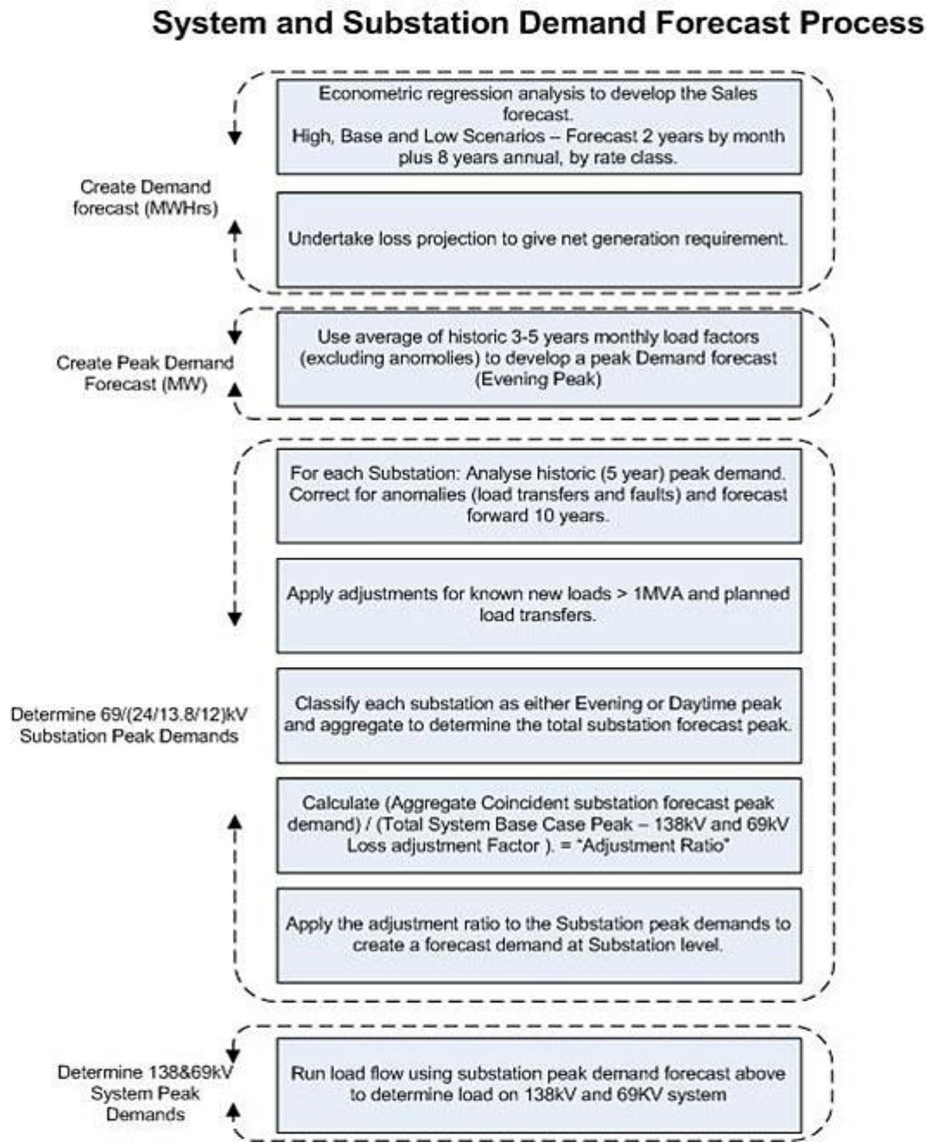
a. determine the interconnection requirements for any Users System, submitted in accordance with the interconnection application process, including any reinforcement, protection or power quality improvement requirements; and

b. determine the interconnection requirements for any Generators System, submitted in accordance with the interconnection application process, including any reinforcement, protection or power quality improvement requirements.

DC 3.6.2 Demand Forecasts

Demand forecast are required to enable the network to be developed in a coordinated and economic manner. A consumption forecast using an econometric regression methodology is considered suitable for this. This forecast of unit consumption is then to be developed into a peak demand forecast for each substation which will inform the studies outlined further in this section.

The overall process for development of the demand forecast at substation level is as below. This should be undertaken on an annual basis in line with the planning timescales in sub-section DC 3.3.



DC 3.6.3 Load Flow Studies

The System Operator will undertake load flow studies using appropriate modelling tools.

Load flows will be modelled at peak feeder loads, based on the feeder metering data or SCADA data where metering data is not available, with forecasts at a feeder level based on regression analysis and forecast forward for an appropriate period to ensure that all network components are operating within their design parameters for the forecast period.

Load flows will model the contingency scenarios planned for in the network design and will be undertaken to ensure that all network components are operating within their design parameters for all plausible scenarios of supply network reconfiguration. Short term and emergency ratings of plant may be used if it is considered that the timescale for restoration to normal operation will align with the manufacturers' guidance on such ratings, or other parameters as determined by the System Operator.

DC 3.6.4 Voltage Drop Studies

The System Operator will undertake voltage drop studies to determine the voltages at all Interconnection Points using appropriate modelling tools. Such studies will be used to determine the impact of any load interconnection, generation interconnection, System extension or reinforcement.

The planning of Voltage regulation will be in accordance with the principles in Engineering Standard ES-1300 section 1.2.3. These principles recommend that voltage regulation planning takes into account 5 year load growth forecasts and includes the use of:

a. tap changers to maintain bus bars at constant voltage;

b. line Drop Compensation;

c. in line voltage regulators; or

d. capacitors (fixed capacitor banks should be sized on present requirements rather than growth forecasts to avoid over voltage).

The Distribution System will be planned with voltage controlled level bars on the secondary sides of the 69/24kV, 69/13.8kV and 69/12kV sides of the relevant transformers using automatic tap changers.

Capacitors may be used to provide voltage improvement on the distribution network. Their use will be in accordance with Engineering Standard ES-1300 section 1.2.3.1. which provides guidance in the following applications:

a. reducing the lagging component of circuit current;

b. increasing the voltage level at the load;

c. improving voltage regulation, if the capacitors are properly switched;

d. reducing I2R power loss and I2X kVAr loss in the system because of reduction in current;

e. increasing power factor of source generators;

f. decreasing kVA loading on source generators and circuits to relieve overloads; and reduce demand.

Suitable systems will be employed where required to ensure that excess voltages are not experienced at Interconnection Points during periods of light load or abnormal running conditions.

Voltage regulators may be used to provide level bars or fixed voltage increases at intermediate points on the Distribution network. Their use will be in accordance with Engineering Standard ES-1300 section 1.2.3.2 which covers the rating, determination of optimum location, requirements for bypassing, control settings and economic evaluation of regulators and recommends the determining of size and location after fixed capacitor bank sizes and locations have been determined.

Voltage drops will be modelled at peak feeder loads based on the feeder metering data, or SCADA data where metering data is not available, to ensure that the design voltage at the customer Interconnection Points meet the voltage requirements of this Code.

Voltage drops will be modelled for the contingency scenarios planned for in the network design and will be undertaken to ensure that the design voltage at customer Interconnection Points meets the voltage requirements of this Code for all plausible scenarios of supply network reconfiguration.

Any extension or interconnection to the Distribution System shall be designed in such a way that it does not adversely affect the voltage control employed on the Distribution System. Information on the voltage regulation and control arrangements will be made available by the System Operator if requested by the User.

DC 3.6.5 Short Circuit Studies

The System Operator will undertake fault level studies at all switching points on the network where fault interrupting devices are located. The studies will determine the 3 phase and single phase to ground short circuit levels. Studies will be carried out for the Maximum Plant and Minimum Plant conditions.

The System should normally be designed to ensure that the short-circuit fault current does not exceed 80% of the declared manufacturers ratings of all switches, fuses, circuit breakers and other protective devices in terms of both Breaking Capacity and Making Capacity.

Where it is identified that the design Breaking Capacity or Making Capacity is likely to be exceeded, the non-compliance should be documented and the plant subject to appropriate operational restrictions until compliance is achieved.

The System Operator and User will exchange information on fault infeed levels at Interconnection Points. This shall include:

a. the maximum and minimum three-phase and line to ground fault in feeds; and

b. the X/R ratio under short circuit conditions.

Unless the System Operator agrees otherwise it is not acceptable for a User or Embedded Generator to limit fault current infeed to the s Distribution System through the use of protection and associated Equipment if the failure of that protection and associated Equipment could cause the s Distribution System to operate outside its short circuit rating.

DC 3.6.6 System Loss Studies

System loss studies shall be performed to quantify the losses in the Distribution System and determine optimum System open points to provide an acceptable balance between reduced losses and System reliability.

Where investment in the System is required, lower loss solutions, in terms of plant and System configuration should be evaluated as part of the alternative solutions and appropriate allowances made in the economic appraisal for any benefit arising from the adoption of such solutions.

DC 3.6.7 Reliability

System reliability studies shall be carried out to determine the theoretical levels of SAIDI and SAIFI for the System using average fault rates for System components. These studies will be used to determine optimum System configurations when undertaking any interconnection, extension to or reinforcement of the distribution System.

SAIDI and SAIFI have the definitions as described in IEEE Standard 1366-1998.

SAIDI – The System Average Interruption Duration Index is the average outage duration for each customer served. It is measured in units of time, minutes or hours, and is calculated as:

$$SAIDI \ \frac{\text{sum of all customer interruption durations}}{\text{total number of customers served}}$$

SAIFI - The System Average Interruption Frequency Index is the average number of interruptions that a customer would experience. It is measured in units of interruptions per customer, usually over the course of a year, and is calculated as:

$$SAIFI \; \frac{\text{sum of all customer interruptions total}}{\text{number of customers served}}$$

DC 3.6.8 System Grounding

System grounding will be in accordance with the Systems Grounding Regulations in Licensee Engineering Standard ES-1300 section 2.7.

a. System Grounding will be designed to the following key principles: To protect life from danger or electric shock, and property from damage.

b. To limit the voltage upon a circuit when exposed to higher voltages than that for which the circuit is designed.

c. In general to limit AC circuit voltages to Ground to 150V or less on circuits supplying interior wiring Systems; and

d. To limit the voltage on a circuit which might otherwise occur through exposure to lightning.

DC 3.7 Standard Planning Data

DC 3.7.1 Energy and Demand Forecast

Where the System Operator considers it necessary, the User shall provide the System Operator with its Energy and Demand forecasts at each Interconnection Point for the five succeeding years.

This forecast data, for the first year will include monthly Energy and Demand forecasts, while the remaining four years will include only annual forecasts.

The Users shall provide the net and gross values of Energy and Demand forecast. The net values will be less any deductions to reflect the output of Customer Generating Plant.

The following factors shall be taken into account by the System Operator and Users when forecasting demand:

a. Historical Demand Data;

b. Demand Trends;

c. Customer Self Generating Plant Schedules; and

d. Demand Transfers.

DC 3.7.2 Distribution System Data

The System Operator shall have available all the data relevant to the Distribution System itself. This network data includes the following:

Transformers (Including Voltage Regulators) - The primary input data for transformers includes MVA rating, primary and secondary winding voltages, windings interconnection, sequence impedances, X/R ratio, tap ranges, tap settings, emergency ratings.

Distribution Lines -The primary input data required among other things are line voltage, conductor type, and type of construction, thermal ratings, emergency rating, and sequence impedances.

Embedded Generators - Generators are modelled by their real and reactive power capabilities for steady state analysis. For dynamic analysis more detailed mathematical models are required for generators, exciters and governor control Systems. The generators are represented by their mathematical model which includes the synchronous, transient and sub transient reactance and inertia constants. The excitation and governor control Systems are modelled by their type 1 excitation and type 10 general-purpose governor control model respectively.

Other Parameters - In order to develop a reliability data bank outage rates and durations for all major equipment are also necessary.

DC 3.7.3 User System Data

For Low Voltage connected Users the following data will be required by the

a. Maximum power requirement (kVA or kW)

b. Type and number of significant load items (Cookers, Showers, Motors, and Welders etc.)

For Users Connected at High Voltage the following data will be provided to the System Operator;

a. connected Load including type and control arrangements; and

b. Maximum Demand.

For Fluctuating and Cyclical Loads:

c. the rate of change of demand;

d. the switching Interval; and

e. the magnitude of the largest step change.

DC 4 EMBEDDED GENERATORS

DC 4.1 General

Embedded Generators can have a significant effect on the Distribution System and as a result it's Users. To enable the System Operator to assess the impact that the Embedded Generator will have on the System they will be required to provide the information outlined in sub-section DC 4.2 Table DC 4.2.

Embedded Generators shall comply with the Licensee Distributed Generation interconnection technical guidelines.

DC 4.2 Provision of Information

The System Operator will use information provided in the planning of the Distribution System and the assessment of interconnection requirements in terms of the voltage level to which the interconnection should be made and any other requirements to enable the interconnection of the Generator.

All Generators shall provide the following information below:

Table DC 4.2

Data Description	Units
Terminal Volts	kV
Rated kVA	kVA
Rated kVAr	kVAr
Maximum generation	kW
Reactive Power required	kVAr
Type of Generator	Text
Type of Prime Mover	Text
Annual Operating Regime	Text
Fault Level contribution	MVA
Method of Voltage Control	Text
Generator Step-up Transformer Details	Text

Rated Capacity	MVA
Voltage Ratio	Text
Impedance	% on specified base

Table DC 4.2.1

Data Description	Units
Rated MW at Registered Capacity for individual units and the Power Station	MW
Rated MW at Minimum Generation for individual units in the Power Station	MW
Auxiliary Active Power demand for individual units and the Power Station at Registered Capacity	MW
Auxiliary Reactive Power demand for individual units and the Power Station at Registered Capacity	MVAr
Auxiliary Active Power demand for individual units and the Power Station under Minimum Generation	MW
Auxiliary Reactive Power demand for individual units and the Power Station under Minimum Generation	MVAr
Individual Generator Information	
Rating	MVA
Generator MW/MVAr Capability Chart	Text
Total Inertia Constant of Prime Mover and Generator	MWsec/MVA
Stator Resistance	% on specified base
Direct axis synchronous, transient and sub-transient reactance	% on specified base
Quadrature axis synchronous, transient and sub-transient reactance	% on specified base

Direct axis synchronous, transient and sub-transient time constants	secs
Quadrature axis synchronous, transient and sub-transient time constants	secs

Under certain circumstances more or less detailed information than that specified above may be required. Additional data requirements are outlined in the Distribution Interconnections provisions and Distribution Data Registration provisions of this Distribution Code.

DC 5 DISTRIBUTION INTERCONNECTION

DC 5.1 Introduction

This section of the Distribution Code specifies the normal method of interconnection to the Distribution System and the minimum technical, design and operational criteria which must be complied with by any User or prospective User.

For the purpose of the Distribution Interconnection section of the Code, User refers to both Embedded Generators and Customers connected to the Distribution System.

In addition, details specific to each User's interconnection may be set out in a separate Interconnection/Interconnection Agreement or in some cases a Power Purchase Agreement. The interconnection conditions set out in this Code are complementary to these Agreements.

All interconnection costs and responsibility shall normally be borne by the User connected to the Distribution System unless specified otherwise by an Interconnection Agreement or policy or as dictated by the OUR.

The Licensee Line Extension Policy provides for the process and commercial aspects of managing User interconnections to the System.

DC 5.2 Objective

The objective of the Distribution Interconnection section of the Code is to ensure that by specifying minimum technical, design and operational criteria the basic rules for interconnection to the Distribution System shall enable Licensee in its capacity as System Operator to comply with its statutory and Licence obligations.

Distribution Interconnection applies to the following:

a. Licensee in its capacity as Distribution System operator at the Interconnection Points to the Distribution System; b. Customers directly connected to the Distribution System, and Generators connected to the Distribution System (Embedded Generators).

DC 5.3 Method of Interconnection

The System Operator in consultation with the User shall determine the optimum interconnection method on the basis of several technical and economic factors including:

a. geographical considerations including proximity to the Distribution System;

b. Maximum Demand to be supplied;

c. Generating Facility MW capacity;

d. Supply voltage;

e. Reliability considerations;

f. Standby or auxiliary power requirements;

g. Substation configuration; and

h. costs.

The studies to be undertaken to determine the works required to facilitate an interconnection are those outlined in the Distribution Planning Code and serve to ensure that for any new interconnection the proposed customer(s) and all existing Customers receive a supply within the statutory parameters.

Multiple Interconnections Points shall not be provided to Interconnection Sites.

No interconnection of the Systems from two different Interconnection Points shall be allowed unless specifically detailed in the Interconnection Agreements and appropriate safeguards put in place.

It should be noted that it shall not be technically or economically practicable to achieve uniformity of the method of interconnection. In all cases, Prudent Utility Practice shall influence the method adopted.

The provisions relating to interconnection to the Distribution System are contained in the Interconnection Agreement with a User and include provisions relating to both the submission of information and reports relating to compliance with the relevant Interconnection Conditions for that User, Safety Rules, commissioning and periodic testing programmes, Operation Diagrams, approval to connect, any Power Purchase Agreement and the Terms and Conditions of Service.

DC 5.3.1 Interconnections at Low Voltage

For low voltage interconnections, supply shall be provided at:

a. single phase 110V;

b. single Phase110/220V; or,

c. three phase 220V Delta

d. three Phase 415/240V Star dependent on User requirements and availability in the location required.

The information required for low voltage interconnections shall be a minimum of:

a. Customer name, TRN, address and contact details;

b. location of proposed interconnection;

c. type of interconnection (Residential, Commercial, Industrial);

d. Capacity required (if not known then type of use appliances etc);

e. identification of any large motors or welders.

Normal interconnections shall be provided by up to three single phase pole mounted transformers of maximum capacity 3x100 KVA (300 KVA) appropriately connected. Transformer ratings and interconnections shall be in accordance with Engineering Standard ES-1300-2.8.

Interconnections may be provided by ground mounted three phase pad mount transformers for capacity requirements greater than 300 KVA or where specific User requests are made.

The normal or standard method of low voltage supply will utilize overhead lines. The interconnection will be a single interconnection of the appropriate number of phases. No alternative is normally provided. Underground cables may be used in the central business area or due to specific User request. The charging policy outlined in the Licensee Standard Terms and Conditions of Service approved by the OUR shall apply to requests for non-standard interconnection.

The interconnection will be made to an appropriate point on the customer premises approved by the Government Electrical Regulator. The customer may be required to provide for the interconnection from this Interconnection Point to the Metering Point.

The Metering Points shall be accommodated in metering facilities provided by the Customer. These metering facilities shall comply fully with the requirements of Engineering Bulletin No. TSD 007/3 Metering Facility Policy and the Standard Terms and Conditions of Service.

The distance between the Interconnection Point and the Metering Point should be minimized and should not exceed 30 meters... It is also desirable that any such interconnection between the Interconnection Point and the Metering Point is secured to prevent unauthorized access.

DC 5.3.2 Interconnection at Medium Voltage (MV)

For interconnections given at MV level, then prior to the Completion Date under the Interconnection Agreement, the following, (as applicable) may be requested to be supplied by the User to the System Operator:

a. Updated Planning Code data with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for items such as Demand;

b. Details of the Protection arrangements and settings including

c. Protection and Control single line diagrams;

d. Copies of all Safety Rules and Local Safety Instructions applicable at Users Sites which shall be used at the System Operator/User interface;

e. Information to enable the System Operator to prepare Site Responsibility Schedules on the basis of the provisions set out in Appendix A;

f. An Operation Diagram for all MV Apparatus on the User side of the Interconnection Point;

g. The proposed name of the User Site (which shall not be the same as, or confusingly similar to, the name of any Licensee Site or of any other User Site);

h. A list of Safety Coordinators;

i. A list of the telephone numbers for Joint System Incidents at which senior management representatives nominated for the purpose can be contacted and confirmation that they are fully authorized to make binding decisions on behalf of the User;

j. A list of managers who have been duly authorized to sign Site Responsibility Schedules on behalf of the User; and

k. Information to enable System Operator to prepare Site Common Drawings.

Such interconnections shall normally be overhead and provided from a radial feeder. The interconnection shall not normally be designed to provide a switched alternative supply for faults on the Distribution System that supplies the Customer. The Service Area concept is used as outlined in the Planning Code to determine appropriate network configuration and any reinforcement required to enable the interconnection to be accommodated onto the System. The interconnection shall be designed to comply with the Guaranteed and Overall Standards of restoration.

Alternative supply arrangements may be requested based on either switched alternative, (Manual or Automatic) or parallel circuit supply. These may be provided at the discretion of the System Operator based on technical considerations. The appropriate charging policy in force at the time shall apply to requests for nonstandard interconnection.

In some cases (for example Subdivisions) a single interconnection to a premise shall be made and multiple Metering Points shall be installed to meter individual Customers. In these cases meters shall only be installed to provide supplies to electrically isolated User Systems.

DC 5.4 Interconnection of Embedded Generators

Generator interconnections shall comply with the requirements of the Generation Code.

In accordance with the Generation Code, Generators with a rated capacity of 10MW or below may be connected to the Distribution System where technical conditions allow. The design of interconnections between any Embedded Generating Unit and the Distribution System shall be as set out in the Generation Code. The design of interconnections between the Distribution System and Customers shall be consistent with the Licence.

The voltage of interconnection shall be at the discretion of the System Operator and based on the relevant studies as described in the Planning Code.

The interconnection of generators to the Distribution System shall be consistent with the OUR Document Ele 2005/08.1 Guidelines for the addition of Generating Capacity to the Public Electricity Supply System (2006) and the Licensee Guide to the Interconnection of Distributed Generation documents as amended from time to time.

Embedded Generation Units shall be required, as a minimum, to meet following performance standards:

a. sustained Operation at any Load within the loading limits and within the System frequency range 49.5 Hz to 50.5 Hz,;

b. Emergency Operation at any Load within the loading limits within the System frequency range 48.0 Hz to 52.5 Hz during exceptional conditions;

c. maintain normal rated output at the voltages specified in DC 2.2.1.

d. sustained Operation at the rated Power Factor set out in the Interconnection Agreement.

Embedded Generation Units shall not normally be required to have Black Start facilities.

Embedded Generation units shall not normally be permitted or required to generate when the part of the Distribution System to which they are connected is disconnected from the Transmission System. Any such permission or requirement shall be detailed in the Interconnection Agreement along with detailed requirements for the voltage and frequency control.

DC 5.5 Interconnection of Variable Renewable Power Plant (VRPP)

The VRPP Operator shall operate and maintain the Generating Units in such a manner so as not to adversely affect Licensee' distribution of electricity, including but not limited to adverse effects on Licensee' voltage level or voltage waveform, power factor and frequency or produce adverse levels of voltage flicker and/or voltage harmonics.

Users should refer to the document 'Licensee Guide to Interconnection of Distributed Generation' section 4 Interconnection Technical Requirements for technical details.

DC 6 POWER QUALITY STANDARDS

DC 6.1 Power Quality

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 is measured in the Distribution System during normal conditions. The standards applicable to Power Quality are set out in the System Operator's Power Quality Policy and System Operation Policy No 2 Operational Standards of Security of Supply which shall be approved by the OUR and amended from time-to-time.

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 50 ± 0.2Hz;

b. Voltage magnitudes are outside their allowable range of variation;

c. Harmonic Frequencies are present in the System;

d. the magnitude of the phase voltages are unbalanced;

e. the phase displacement between the voltages is not equal to 120 degrees;

f. Voltage Fluctuations cause Voltage Flicker that is outside the allowable Flicker Severity limits; or

g. High frequency over voltages are present in the Distribution System.

DC 6.1.1 Frequency Variations

The frequency of the Distribution System shall be consistent with Licensee System Operation Policy No.2 and have a normal frequency of 50Hz ± 0.2Hz and shall be controlled within the limits of 49.5 and 50.5 Hz.

Under some conditions the system frequency could rise to 52.5 Hz or fall to 48.0 Hz and shall be taken into account in the design of Plant and Apparatus.

DC 6.1.2 Power Factor

The User shall maintain power factor at the Interconnection Point to the Distribution System consistent with Licensee Standard Terms and Conditions of Service as amended from time to time.

The System Operator shall correct Reactive Power Demand on feeders and substations to a level that will economically reduce technical losses and maintain a minimum power factor of 0.95 lagging on the Distribution System.

DC 6.1.3 Voltage Variations

The voltage on the 24 kV, 13.8kV and 12 kV parts of the Distribution System at each Interconnection Site with a User shall normally remain within –5% of the nominal value.

The voltage on the lower voltage side of transformers at Interconnection Sites with Users shall be consistent with the Licensee Standard Terms and Conditions of Service as amended from time to time.

DC 6.1.4 Voltage Waveform Quality

All Plant and Apparatus connected to the Distribution System, and that part of the Distribution System at each Interconnection Site, should be capable of withstanding distortions of the voltage waveform in respect of harmonic content and phase unbalance as outlined in the System Operator Power Quality Policy.

DC 6.1.5 Exceptional Conditions

Some events such as system faults which involve the Transmission System or a generating plant or faults that lead to loss of more than one generating set in the System or where a Significant Incident has occurred or during constrained operating conditions such as light load conditions and shortage of Active/Reactive Power, can result in variations outside the normal power quality standards as outlined in section DC 6 and its subsections. During these events, the System Operator shall be relieved of its obligation to comply with the System conditions referenced in the aforementioned.

DC 7 PLANT AND APPARATUS RELATING TO INTERCONNECTION SITES

DC 7.1 General Requirements

All Plant and Apparatus relating to the Users/System Operator at the Interconnection Point, shall be compliant with the following requirements in DC 7.0 and its subsections.

DC 7.2 Substation Plant and Apparatus

All circuit breakers, switch disconnectors, earthing devices, power transformers, voltage transformers, reactors, current transformers, surge arresters, bushings, neutral equipment, capacitors, line traps, coupling devices, external insulation and insulation co-ordination at the User/Licensee Interconnection Point shall be constructed, installed and tested in accordance with the current edition at the time of construction of the following Codes and standards, or their international equivalents and Prudent Utility Practice:

ACI	American Concrete Institute
ANSI	American National Standards Institute
ASCE	American Society for Civil Engineers
ASME	American Society for Mechanical Engineers
ASNT	American Society for Non-Destructive Testing
ASTM	American Society for Testing Materials
AWS	American Welding Society
BSJ	Bureau of Standards Jamaica

IEC	International Electro-technical Commission
IEEE	Institute of Electrical and Electronic Engineers
ISO	International Organization for Standardization
NBCJ	National Building Code of Jamaica
NEC	National Electric Code
NEMA	National Electric Manufacturers Association
NEPA	Natural Environmental and Planning Agency (Jamaica)
NESC	National Electric Safety Code
NETA	National Electric Testing Association
NFPA	National Fire Protection Association
OSHA	Occupational Safety and Health Administration
SSPC	Steel Structures Painting Council
UL	Underwriters Laboratory

Plant and Apparatus shall be designed, manufactured and tested in premises certified in accordance with the quality assurance requirements of ISO 9001 or equivalent.

DC 7.3 Generator Interconnection Points

The requirements for the design of Interconnection Points between Generators and the System Operator are set out in the Generation Code. For information the following sections are extracted from the Generation Code, minor wording modification have been made to refer to Distribution interconnections.

The Generation Code states that the voltage level at which the Generating Unit(s) are connected to the Transmission or Distribution System shall be dependent on but not limited to the size and number of units and the other factors that determine the Interconnection Point. Subject to other technical considerations, Generating Units with a Rated Capacity of 10 MW or above shall be connected to the Transmission System at 69 kV or 138 kV. Generating Units with a Rated Capacity of below 10 MW may be connected to either the Transmission System at 69 kV or 138 kV or the primary Distribution System at 24 kV or less. The chosen method of interconnection shall be determined by the System Operator on the grounds of system security, stability and safety.

All Substations shall have the capability to disconnect or separate, from the Distribution System, any line and/or Generating Unit which is interconnected to the Substation.

The Generation Code states that the method of interconnection of Generating Unit(s) shall be determined on the basis of several technical and economic factors which include:

a. proximity to System Grid;

b. Generating Unit MW rating or Generating Facility MW capacity;

c. Supply voltage;

d. Reliability considerations;

e. Auxiliary power supply;

f. Substation configuration; and

g. costs.

It should be noted that it will not be technically or economically practicable to achieve uniformity of the method of interconnection. In all cases however, Prudent Utility Practice shall influence the method adopted.

DC 7.4 Interconnection Points to Transmission System

The Distribution System interconnection to the Transmission System shall comply with sub-section TC 4.4 of the Transmission Code.

DC 7.5 Protection Requirements

The protective Systems to be applied to Generating Units are set out in the Generation Code and shall, as a minimum, have protection against the following incidents unless specifically agreed with the System Operator:

a. loss of excitation;

b. under excitation;

c. unbalanced load Operation;

d. stator phase faults and earth faults;

e. reverse power protection;

f. main Generating Unit Step Up transformer phase and earth faults, HV and LV;

g. Station service transformer phase and earth faults, HV and LV;

h. Transformer tank sudden pressure;

i. Backup protection in the event that external phase and earth faults are not cleared by remote protection System;

j. Backup protection in the event of circuit breaker failure to operate;

k. Generating Unit over and under frequency;

l. generator over speed;

m. stator over temperature;

n. rotor over temperature; and

o. restricted earth fault.

All protection Systems and settings shall be in accordance with the System Operators protection policy as contained in the document Licensee Protective Relaying Philosophy & Practices.

Protection of the Distribution System and Customers directly supplied from the Distribution System shall be designed, coordinated and tested to achieve the desired level of speed, sensitivity and discrimination to isolate the affected parts of the System while ensuring that the section isolated does not include parts of the System not directly affected by the fault, as far as possible in accordance with Prudent Utility Practice, and maintaining supplies to the remainder of the System within design parameters.

The System Operator shall be solely responsible for the protection of the Distribution System. Users and Embedded Generators shall be solely responsible for the protection of the User Systems on their side of the Interconnection Point.

Users shall design their protection System to ensure that no other User shall be affected for faults on their System.

The reliability of the protection scheme to initiate the successful tripping of the Circuit Breakers that are associated with the faulty Equipment shall be consistent with Prudent Utility Practice.

The System Operator may require specific Users to provide other protection schemes, designed and developed to minimize the risk and/or impact of disturbances on the System.

Where as part of the Interconnection Agreement, a User is required to provide Demand disconnection as part of the System Operators under frequency management process that includes the automatic disconnection of substations and feeders then the relays shall comply with the requirements of Appendix B.

DC 8 SITE RELATED CONDITIONS

DC 8.1 General

In the absence of agreement between the Parties to the contrary, construction, commissioning, control, operation and maintenance responsibilities follow ownership.

DC 8.2 Responsibilities for Safety

Before interconnection to the Distribution System at the MV level the System Operator and the User shall enter into a written agreement as to the Safety Rules to be used for work on Plant and/or Apparatus at the Interconnection Point

DC 8.3 Site Responsibility Schedules

In order to inform site operational staff and the System Operator s Control Engineers of agreed responsibilities for Plant and/or Apparatus at the Operational Interface at the MV level, a Site Responsibility Schedule shall be produced for System Operator and Users with whom they interface.

The format, principles and basic procedure to be used in the preparation of Site Responsibility Schedules are set down in Appendix A. These documents should be into the Interconnection (Interconnection) Agreements.

DC 8.4 Operation Diagrams

An Operation Diagram shall be prepared for each Interconnection Site at which a Interconnection Point is at the MV level in accordance with Appendix C. Users shall provide Operation Diagrams of their Apparatus to the System Operator in a suitable form as specified by the System Operator.

The Operation Diagram shall include all MV Apparatus and the interconnections to all external circuits and incorporate numbering, nomenclature and labelling, as set out in the Operations Code. At those Interconnection Sites where SF6 gas-insulated metal enclosed switchgear and/or other SF6 gas-insulated MV Apparatus is installed, those terms must be depicted within an area delineated by a chain dotted line which intersects SF6 gas-zone boundaries. The nomenclature used shall conform to that used on the relevant Interconnection Site and circuit.

The Operation Diagram (and the list of technical details) is intended to provide an accurate record of the layout and circuit interconnections, ratings and numbering and nomenclature of Apparatus and related Plant.

DC 8.5 SF6 Gas Zone Diagrams

An SF6 Gas Zone Diagram shall be prepared for each Interconnection Site at which a Interconnection Point exists where SF6 gas-insulated switchgear and/or other SF6 gas-insulated MV Apparatus is utilised. This is to ensure that responsibility for the SF6 gas is documented and is particularly important as the chamber containing the insulating medium can extend beyond the Interconnection Point. They shall use, where appropriate the graphical symbols shown in Appendix C. The nomenclature used shall conform to that used in the relevant Interconnection Site and circuit.

DC 8.6 Preparation of Operation and SF6 Gas Zone Diagrams

Each party shall provide to the other party an Operation Diagram and details of the SF6 Gas Zones on its side of the Interconnection Point. The party owning the Interconnection Site is then responsible for the preparation of a composite Operation Diagram and SF6 Gas Zone diagrams for the site.

DC 8.7 Changes to Operation and SF6 Gas Zone Diagrams

When either party has decided that it wishes to install new MV Apparatus or it wishes to change the existing numbering or nomenclature of its MV Apparatus at an Interconnection Point it shall one month prior to the installation or change, send to the other party a revised Operation Diagram of that Site, incorporating the new MV Apparatus to be installed and its numbering and nomenclature or the changes, as the case may be.

DC 8.8 Validity

The composite Operation Diagram prepared by System Operator or the User shall be the definitive Operation Diagram for all operational and planning activities associated with the Interconnection Site. If a Dispute arises as to the accuracy of the composite Operation Diagram, a meeting shall be held at the Interconnection Site, as soon as reasonably practicable, between the System Operator and the User, to endeavor to resolve the matters in Dispute.

DC 8.9 Site Common Drawings

Site Common Drawings shall be prepared for each Interconnection Site which is connected at the MV level and shall include Interconnection Site layout drawings, electrical layout drawings, common Protection/control drawings and common services drawings.

In the case of a User Interconnection Site, the System Operator shall prepare and submit to the User, Site Common Drawings for the System Operator side of the Interconnection Point in accordance with the requirements of the Interconnection Agreement.

The User shall then prepare, produce and distribute, using the information submitted by the System Operator, Site Common Drawings for the complete Interconnection Site in accordance with the requirements of the Interconnection Agreement.

In the case of a System Operator Site, the User shall prepare and submit to the System Operator Site Common Drawings for the User side of the Interconnection Point in accordance with the requirements of the Interconnection Agreement.

The System Operator shall then prepare, produce and distribute, using the information submitted by the User, Site Common Drawings for the complete Interconnection Site in accordance with the requirements of the Interconnection Agreement.

DC 8.10 Changes to Site Common Drawings

When the System Operator or a User becomes aware that it is necessary to change any aspect of the Site Common Drawings at an Interconnection Site it shall notify the other Party and amend the common site drawings in accordance with the procedure set out in sub-section DC 8.9.

If the change can be dealt with by notifying the other Party in writing of the change and for each party to amend its copy of the Site Common Drawings then each party shall so amend.

DC 8.11 Validity of Site Common Drawings

The Site Common Drawings for the complete Interconnection Site prepared by the User or the System Operator as the case may be, shall be the definitive Site Common Drawings for all operational and planning activities associated with the Interconnection Site. If a Dispute arises as to the accuracy of the Site Common Drawings, a meeting shall be held at the site, as soon as reasonably practicable, between the System Operator and the User, to endeavor to resolve the matters in Dispute.

DC 8.12 Access

The provisions relating to access to System Operator Sites by Users, and to User Sites by the System Operator are set out in each Interconnection Agreement with the System Operator and each User and/or Standards Terms and Conditions of Service.

In addition to those provisions, where a System Operator Site contains exposed MV conductors, unaccompanied access shall only be granted to individuals holding an Authority for Access issued by the System Operator.

DC 8.13 Maintenance Standards

All Plant and Apparatus at the Interconnection Point shall be operated and maintained in accordance with Prudent Utility Practice and in a manner that shall not pose a threat to the safety of any personnel or cause damage to the Plant and Apparatus of the System Operator or the User.

The User shall maintain a log containing the test results and maintenance records relating to its Plant and Apparatus at the Interconnection Point and shall make this log available when requested by the System Operator.

The System Operator shall maintain a log containing the test results and maintenance records relating to its Plant and Apparatus at the Interconnection Point and shall make this log available when requested by the User.

Either Party shall have the right to inspect the test results and maintenance records relating to the other Party's Plant and Apparatus at any time.

DC 9 COMMUNICATIONS AND CONTROL

In order to ensure control of the Distribution System, telecommunications between User(s) and the System Operator must be established if required by the System Operator.

Control Telephony is the method by which a User's Responsible Engineer/Operator and the System Operator's Control Engineers speak to one another for the purposes of control of the Distribution System in both normal and emergency operating conditions.

At any Interconnection Point where the Users telephony Equipment is not capable of providing the required facilities or is otherwise incompatible with the System Operators control telephony, the User shall install appropriate telephony Equipment to the specification of the System Operator. Details of, and relating to, the control telephony required shall be set out in the Interconnection Agreement.

The System Operator shall provide Supervisory Control and Data Acquisition (SCADA) outstation interface Equipment. The User shall provide such voltage, current, frequency, Active Power and Reactive Power measurement outputs and Plant status indications and alarms to the System Operator SCADA outstation interface Equipment as required by the System Operator in accordance with the terms of the Interconnection Agreement. The manner in which information is required to be presented to the outstation Equipment is set out in Appendix [D]

DC 10 TESTING AND MONITORING

DC 10.1 Introduction

To ensure that the Distribution System is operated efficiently and within Licence Conditions and to meet statutory actions the System Operator shall organize and carry out testing and/or monitoring of the effect of Users electrical Apparatus on the Distribution System.

The Testing and/or Monitoring Procedures shall be specifically related to the technical criteria detailed in the Distribution Planning section DC 3 and Distribution Interconnection section DC5. They shall also relate to the parameters submitted by Users in the Distribution Data Registration section.

The testing carried out under this Distribution Operations section 4 (DC 10) should not be confused with the more extensive Special System Tests outlined in section DC 17.

DC 10.2 Objective

The objective of section DC 10 is to specify the requirement to test and/or monitor the Distribution System to ensure that Users are not operating outside the technical parameters required by the Distribution or Supply Codes.

Procedure related to quality of supply

The System Operator shall from time to time determine the need to test and/or monitor the quality of supply at various points on its Distribution System.

The requirement for specific testing and/or monitoring may be initiated by the receipt of complaints as to the quality of supply on its Distribution System.

In certain situations the System Operator may require the testing and/or monitoring to take place at the Interconnection Point of a User with the Distribution System.

Where testing and/or monitoring is required at the Interconnection Point, the System Operator shall advise the User involved and shall make available the results of such tests to the User. These tests shall be performed by the System Operator at the System Operator's cost.

Where the results of such tests show that the User is operating outside the technical parameters specified in the Distribution or Supply Codes, the User shall be informed accordingly.

Where the User requests the System Operator to perform a retest, the retest shall be carried out at the User's cost and witnessed by a User representative.

A User shown to be operating outside the limits specified in the Distribution or Supply Codes shall rectify the situation or disconnect the Apparatus causing the problem from its electrical System connected to the Distribution System immediately or within such time as is agreed with the System Operator.

Continued failure to rectify the situation may result in the User being disconnected in accordance with the Interconnection Agreement from the Distribution System either as a breach of the Distribution or Supply Codes or other statutory requirement where appropriate.

The User may conduct test(s) on the User's side of the Interconnection Point at the User's cost, however the System Operator shall be notified prior to such test(s).

DC 10.3 Procedure Related to Interconnection Point Parameters

The System Operator from time to time shall monitor the effect of the User on the Distribution System. The monitoring will normally be related to amount of Active Power and Reactive Power transferred across the Interconnection Point.

Where the User is exporting to or importing from the Distribution System Active Power and Reactive Power in excess of the parameters in the Interconnection Agreement the System Operator shall inform the User and where appropriate demonstrate the results of such monitoring.

The User may request technical information on the method of monitoring and, if necessary, request another method reasonably acceptable to the System Operator.

Where the User is operating outside of the specified parameters, the User shall immediately restrict the Active Power and Reactive Power transfers to within the specified parameters.

Where the User requires increased Active Power and Reactive Power in excess of the physical capacity of the Interconnection Point, the User shall restrict power transfers to those specified in the Interconnection Agreement until a modified Interconnection Agreement has been applied from the System Operator and physically established. All costs to increase the physical capacity of the Interconnection Point shall be the responsibility of the User.

DC 11 DEMAND CONTROL

DC 11.1 Introduction

This sub-section of the Distribution Code is concerned with the provisions to be made by the System Operator or a User with Systems connected to the Distribution System, in certain circumstances, to permit reductions in total Demand in the event of insufficient Generating Plant being available to meet total Demand or to avoid disconnection of Customers or in the event of breakdown and/or overloading on any part of the Transmission and/or Distribution Systems.

The sub-section also deals with the following method of reducing Demand or Demand Control:

a. Block (Manual) Load Shedding initiated by the System Operator;

b. User disconnection;

c. Automatic under frequency load shedding; and

d. Emergency manual distribution feeder disconnection.

The term Demand Control is used to describe any or all of these methods of achieving a Demand reduction.

DC 11.2 Objective

To establish procedures to enable the System Operator to achieve a reduction in Demand in order to avoid a Breakdown or Overloading of any part of the Total System in a manner that does not unduly discriminate against or unduly prefer any one or group of Customers.

DC 11.3 Procedure

The System Operator shall arrange within the Distribution System a scheme to reduce load in a controlled manner by any of the following methods:

a. Disconnecting Customers (either manually or by a disconnection scheme);

b. Automatic under frequency disconnection;

c. By instruction; or

d. By reduction of System voltage.

DC 11.3.2 Issue of warnings for Operational System load reduction

A System of warnings shall be contained within the load reduction arrangements to give notice, wherever practical, of possible implementation.

DC 11.3.3 Automatic disconnection of Demand by Under frequency Relays

The System Operator shall arrange to have available at selected locations protection relays to detect progressively low frequency conditions on the System and shall provide for a percentage of System Demand to be disconnected automatically in progressive stages.

The areas of Demand affected by the under frequency disconnection scheme should be such as to allow the Demand relief to be uniformly applied throughout the Distribution System, but may take into account any operational requirements and essential load.

DC 11.3.4 Emergency manual disconnection of Demand

The System Operator shall arrange to have available a rotating block load shedding scheme based on Interconnection Points with the Distribution System. The scheme shall be designed to be called into Operation in the event of a generation shortfall or depressed voltage, and shall be implemented in predetermined timescales to disconnect Demand in stages.

DC 11.3.5 Co-ordination of actions

Where Demand Control is exercised by the System Operator in order to safeguard the Distribution System, the System Operator shall liaise with and inform Users accordingly so far as is practical.

DC 11.4 Load Shedding Procedures

DC 11.4.1 Under Frequency (Automatic) Load Shedding

During incidents in which the frequency decay is such that the Generating Units' governors cannot adequately compensate for the decay, the Under-Frequency Load Shedding Scheme is designed to shed the appropriate amount of Load to improve the System frequency so as to prevent damage to the Generating Unit(s) and/or collapse of the Power System.

The System Operator shall provide the OUR with the details of the Under-Frequency Load Shedding Scheme which may be in force from time to time and contemporaneously with any relevant changes that may apply.

Low Frequency Alarms

Low frequency alarm relays shall be installed in power station control rooms and shall be set at 49.5 Hz. These alarms will warn Generating Unit Controllers of low frequency problems, but no action shall be taken without verification from the System frequency meter at the System Control Centre.

Low frequency alarm relay shall be installed in the SCADA system and shall similarly be set at 49.5 Hz.

Action at Low Frequency Alarms

At a low frequency alarm, Generating Unit Controllers shall confirm:

That the alarm is genuine by reading the analog and digital frequency meters/charts; and

Whether the System is still interconnected and whether the alarm is for the entire System or section(s) thereof.

At the first stage alarm the Generating Unit Controller shall not act to restore the System frequency without prior consultation of the System Control Engineer.

The exception of this rule is allowed when the decay in System frequency results from a loss in Generating Unit output, in which case the appropriate Generating Unit Controllers shall act to restore its former level of output. The System Control Engineer must be informed as soon as possible thereafter.

Action Below 49.5 Hz

At 49.5 Hz and falling the Generating Unit Controller shall act to increase Generating Unit output within operating limits, in order to restore the System frequency and then report action taken to the System Control Engineer.

To help relieve the System overload, the System Control Engineer may carry out further manual load shedding in accordance with section DC 11.4.3.

DC 11.4.2 Action at 48.0 Hz and Falling

In order to save the System from total collapse and prolonged outage, the circuit breakers of the affected Generating Units shall be opened.

The auxiliaries, however, should be on ‘unit supply’ as the objective is not to trip the Generating Unit but to remove it from the System with it operating on its own unit auxiliary power.

After a total System failure is confirmed Generating Units shall be black started as quickly as possible to be ready to restore supply as instructed by the System Control Engineer in accordance with black start procedures.

Should a System failure occur, restoration of the System shall commence as soon as possible in accordance with the procedures set out in sub-section 3.5.2.

DC 11.4.3 Manual Load Shedding

Where there is insufficient generation to meet the Load it may be necessary for the System Operator to institute Load Shedding on a programmed basis. When it is known that generation deficiency will extend over a period of several hours or days, particularly during Peak Hours, such Load Shedding shall be done in blocks consisting of a number of feeders supplying various sections of the System, usually for 1 to 4 hour periods. The Load represented by the blocks shall be arranged to equate the amount of Load shed with the extent of the known generation deficiency and also to equitably distribute the time and period of Load Shedding among the blocks.

A manual Load Shedding procedure may be implemented to rotate the blocks shed after Under-Frequency Load Shedding has taken place. Manual Load Shedding may also be implemented to prevent further Under-Frequency Load Shedding.

Every effort must be made to ensure that the programmed duration of each outage is maintained as near as possible to the planned schedule or for a shorter duration where possible.

Feeders supplying critical Loads should be identified and whenever possible the shedding of these feeders should be avoided.

If the shedding of feeders supplying hospitals and other critical Loads become necessary the following actions must be taken by the System Operator prior to effecting this measure:

a. alert the hospital(s) and critical Loads supplied from the feeder(s); and

b. advise hospital staff to activate stand-by plant if available.

In order to maintain supplies to the maximum number of consumers permitted by available Generating Capacity, the System Control Engineer shall, whenever possible, avoid shedding a complete block of Load when a portion thereof will provide the necessary relief to the Generating Units. The Load Shedding log sheet shall be properly completed.

To achieve Load reduction and upon consultation with higher authority, the System Control Engineer may decide to change the target frequency from 50.0 Hz to a minimum of 49.6 Hz. or reduce bus bar voltages by up to 4% if necessary at all Generating Facilities.

It should be noted that Substation locations having automatic on-load tap changers will attempt to maintain normal voltage. The result of bus bar voltage reduction shall be carefully noted.

Any adverse effect of changing target frequencies and/or voltages on any Generating Unit shall be reported to the System Control Engineer immediately who shall take the necessary corrective action.

DC 12 OPERATIONAL COMMUNICATION

DC 12.1 Introduction

The requirement to notify in section DC 12 does not relate to providing reasons for Incidents and/or Operations but relates generally to communicating what may occur or what has occurred as a result of an Incident and/or Operation causing an Operational Effect.

When an Incident has occurred on the Distribution System, which itself may have been caused or exacerbated by an Operation or Incident on a User System], the System Operator in reporting the Incident on the Distribution System to a User can pass on what it has been told by the User in relation to the Operation or Incident on that User System.

DC 12.2 Objective

To provide for the exchange of information so that the implications of an Operation and/or Incident can be considered and the possible risks arising from it can be assessed and appropriate action taken by the relevant party in order to maintain the integrity of the System and the User System.

Section DC 12 does not seek to deal with any actions arising from the exchange of information, but merely with the exchange of information.

DC 12.3 Communication Procedure

The System Operator and each User connected to its Distribution System shall nominate officers and agree communication channels to make effective the exchange of information required by section DC 12.

Communication should, as far as possible, be direct between the User and the System Operator. However, this does not preclude communication with the User's nominated representative.

Notifications and responses to notifications may be made by telephone or the mass media but shall be confirmed in writing within one (1) hour or as soon as and if it is practical to do so.

A notification under DC 12 shall be given as far in advance as possible and in the event of an Incident shall be given in sufficient time as shall reasonably allow the recipient to reasonably consider and assess the arising implications and risks.

Where given orally a notification shall be dictated to the recipient who shall record it and on completion shall repeat the notification in full to the sender and check that it has been accurately recorded.

Where information is requested in writing throughout this Code, facsimile transmission or other electronic means as agreed with the System Operator in writing maybe used.

DC 12.4 Notification of Operations

In the case of an Operation on a User System connected to the Distribution System, which will have or may have an Operational Effect on the Distribution System, the User shall notify the System Operator in accordance with section DC 12.

In the case of an Operation on the Distribution System or an Operation on the Transmission System, which in the opinion of the System Operator, will have or may have an Operational Effect on a User System connected to the Distribution System, the System Operator shall notify the User. This does not preclude any User of an affected User System asking the System Operator for information regarding the Operation which has affected the User's System

Whilst in no way limiting the general requirement to notify in advance, the following are examples of situations where notification shall be required, in as much as they may have or have had an Operational Effect on the Distribution System or another User System:

a. the implementation of a Scheduled Outage of Plant and/or Apparatus which has been arranged pursuant to section DC 3.

b. the operation of any Circuit Breaker or isolator or any sequence or combination of the two including any temporary Equipment overloads, System parallels, or Generating Unit synchronizing.

DC 12.5 Notification of Incidents

In the case of an Incident on a User System connected to the Distribution System, which has had or may have had an Operational Effect on the Distribution System or on the Transmission System, the User shall notify the System Operator in accordance with this section DC 12.

In the case of an Incident on the Distribution System or on receipt of notification of an Incident on the Transmission System, which in the opinion of the System Operator, will have or may have an Operational Effect on a User System connected to the Distribution System, the System Operator shall notify the User in accordance with this DC 12. This does not preclude any User of an affected User System asking the System Operator for information regarding the Incident which has affected the User's System.

An Incident on the Distribution System may be caused or exacerbated by a prior Incident or Operation on another User's System and in that situation the information to be notified is different from that where the Incident arose independently of any other Incident or Operation.

The following are examples of situations where notification shall be required if they have or may have an Operational Effect:

a. the actuation of any alarm or indication of any abnormal operating condition;

b. adverse weather conditions being experienced;

c. breakdown, faults, or temporary changes in the capabilities of, Plant and/or Apparatus including protection; and

d. increased risk of inadvertent operation of protection devices and equipment.

DC 12.6 Form of Notification

A notification by the System Operator of an Operation on the Distribution System including Operations that may have been caused by another Operation (the First Operation) or by an Incident on a User's System, shall describe the Operation and shall where relevant contain the information which the System Operator has been given in relation to the First Operation or that Incident by the User.

The notification shall be of sufficient detail to enable the recipient of the notification to reasonably consider and assess the implications and consequences arising from the Operation on the Distribution System and shall include the name of the individual reporting the Operation on behalf of the System Operator. The recipient may ask questions to clarify the notification.

A notification by the System Operator of an Operation under DC 12 which has been caused by an Operation or an Incident on the Transmission System, shall describe the Operation on the Distribution System and may contain the information which the System Operator has been given in relation to the Operation or an Incident on the Transmission System.

The notification shall be of sufficient detail to enable the recipient of the notification to reasonably consider and assess the implications and consequences arising from the Operation on the Distribution System and shall include the name of the individual reporting the Operation on behalf of the System Operator. The recipient may ask questions to clarify the notification.

A notification by the System Operator of an Incident on the Distribution System[including Incidents that may have been caused or exacerbated by another Incident (the first Incident) or by an Operation on a User's System] shall describe the Incident and shall where relevant contain the information which the System Operator has been given in relation to the first Incident or that Operation by the User. The notification shall be of sufficient detail to enable the recipient of the notification to reasonably consider and assess the implications and risks arising from the Incident on the Distribution System and shall include the name of the individual reporting the Incident on behalf of the System Operator. The recipient may ask questions to clarify the notification.

The notification shall be dictated, except in an emergency situation, to the recipient who shall record it and on completion shall repeat the notification in full to the sender and check that it has been accurately recorded.

Where a User is reporting an Operation or an Incident on the User's System [including those Operations that may have been caused by an Incident or scheduled/planned action affecting the User's System], the notification to the System Operator shall describe the Operation or Incident and shall contain where relevant the information which the User has in relation to that Incident or scheduled/planned action affecting the User's System. The System Operator may pass on the information contained in the notification to other affected Users with affected User Systems.

The User shall not pass on to other Users with User Systems connected to the System any information contained in a notification received from the System Operator or a notification issued to another User from the System Operator, but shall only say that there has been an Incident on the System and, where applicable and indicated by the System Operator, an estimated time of return to service.

DC 12.7 Significant Incidents

The System Operator may determine than an Incident shall be classified as a Significant Incident in accordance with sub-section DC 12.7.3.

Where an Incident on the Distribution System or a User System has had or may have had a significant Operational Effect on the System and any other User Systems, the Incident shall be reported in writing by the System Operator in accordance with the provisions of sub-section DC 12.7.

Without limiting this general description, a Significant Incident shall include as a minimum any combination of or all of the following:

a. Manual or fault related tripping of System circuits, Plant or Apparatus affecting more than 20% of the Distribution System customer base;

b. Overloading (i.e. loading in excess of 110% of the rated capacity) of

c. System circuits and Plant, or

d. System Instability

e. Breaches of Safety Rules or procedures that resulted in danger or injury to members of the public or the System Operator or to User employees or their representatives.

DC 13 MAINTENANCE STANDARDS

All Plant and Apparatus on the System shall be operated and maintained in accordance with original equipment manufacturers (OEM) recommendations and Prudent Utility Practice and in a manner that shall not pose a threat to the safety of employees or the public.

The System Operator shall establish a Distribution System Maintenance Policy which shall be reviewed and approved by the OUR.

The System Operator shall maintain maintenance records relating to its maintenance of Plant and Apparatus.

DC 14 COMPETENCY OF STAFF

The System Operator shall have in place training polices that serve to ensure that persons operating, maintaining, testing and controlling the System Operator Transmission and Distribution Systems are competent for the tasks to be undertaken. The policies shall include refresher training at appropriate intervals to maintain the currency of the training.

All persons operating, maintaining, testing and controlling the System Operator Transmission and Distribution Systems, shall have received appropriate training to ensure competency for the tasks that they shall be undertaking and refresher training at appropriate intervals to maintain the currency of the training.

The System Operator shall maintain records of training given and issue certificates indicating the areas of competency of the persons trained.

Requirement for inspection

All Plant and Apparatus that shall form part of the Distribution System shall only become part of the Distribution System following inspection and approval by the Government Electrical Regulator

DC 15 SWITCHING INSTRUCTIONS

Medium Voltage switching shall only be carried out with the permission of the System Control Engineer except for agreed routine switching or in case of System Emergencies. Persons required to carry out medium voltage switching must be specifically certified and authorized by the System Operator to carry out such switching.

The following procedures shall be adhered to when carrying out switching operations:

When switchgear, normally operated to the instruction of the System Control Engineer has been operated without instruction from him, the operator concerned shall notify the System Control Engineer immediately. Switchgear normally operated to the instruction of the System Control Engineer shall not be closed without his permission;

The System Control Engineer shall ensure that any instruction for switching issued by him is repeated phrase by phrase as received and at the termination of the message is read back to him in full by the recipient; and

Any instruction issued by the System Control Engineer relating to the operation of switchgear shall, be written down and every such instruction shall be repeated phrase by phrase as received. At the termination of the message it shall be read back in full to sender to ensure that the instruction has been accurately received.

Instructions from the System Control Engineer shall be carried out without delay and at the time of completing, the operation or sequence of operations shall be reported back to the System Control Engineer.

An operator shall inform the System Control Engineer immediately of any objection to any instruction. The System Control Engineer shall then investigate the matter and if necessary refer it to higher authority endowed with the necessary powers of authority, to make a determination on such matters.

DC 16 NUMBERING AND NOMENCLATURE

DC 16.1 Introduction

This section of the Code sets out the responsibilities and procedures for notifying the relevant owners of the numbering and nomenclature of Apparatus at Interconnection Points.

The numbering and nomenclature of Apparatus shall be included in the Operation Diagram prepared for each site having an Ownership Boundary.

DC 16.2 Objectives

The prime objective embodied in section DC 16 is to ensure that at any site where there is an Ownership Boundary every item of Apparatus has numbering and/or nomenclature that has been mutually agreed and notified between the owners concerned to ensure, so far as is reasonably practicable the safe and effective Operation of the Systems involved and to reduce the risk of error.

DC 16.3 Procedure

DC 16.3.1 New Apparatus

When the System Operator or a User intends to install Apparatus on a site having an Ownership Boundary the proposed numbering and/or nomenclature to be adopted for the Apparatus must be notified to the other owners. The notification shall be made in writing to the relevant owners and shall consist of an Operation Diagram incorporating the proposed Apparatus to be installed and its proposed numbering and/or nomenclature. The notification shall be made to the relevant owners at least three months prior to the proposed installation of the Apparatus.

The relevant owners shall respond in writing within one month of the receipt of the notification confirming both receipt and whether the proposed numbering and/or nomenclature is acceptable or, if not, what would be acceptable.

In the event that agreement cannot be reached between the System Operator, and the other owners, the System Operator, acting reasonably, shall have the right to determine the numbering and nomenclature to be applied at that site.

DC 16.3.2 Existing Apparatus

The System Operator and/or every User shall supply the other Party on request with details of the numbering and nomenclature of Apparatus on sites having an Ownership Boundary. The System Operator and every User shall be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature of its Apparatus on sites having an Ownership Boundary.

DC 16.3.3 Changes to existing Apparatus

Where the System Operator or a User needs or wishes to change the existing numbering and/or nomenclature of any of its Apparatus on any site having an Ownership Boundary, the provisions of DC 16 shall apply with any amendments necessary to reflect that only a change is being made.

Where any Party changes the numbering and/or nomenclature of its Apparatus, which is the subject of DC 16, that party shall be responsible for the provision and erection of clear and unambiguous labelling.

DC 17 SPECIAL SYSTEM TESTS

DC 17.1 Introduction

This section of the Code sets out the responsibilities and procedures for arranging and carrying out Special System Tests which have or may have an effect on the System Operators Distribution System or Users Systems. Special System Tests are those tests which involve either simulated or the controlled application of irregular, unusual or extreme conditions on the System or any part of the System, but which do not include commissioning or re-commissioning test or any other tests of a minor nature.

DC 17.2 Objective

The objectives of section DC 17 are to:

a. ensure that the procedures for arranging and carrying out Special System Tests are such that, so far as practicable, Special System Tests do not threaten the safety of personnel or the general public and cause minimum threat to the security of supplies, the integrity of Plant or Apparatus and are not detrimental to the System Operator and Users; and

b. set out procedures to be followed for establishing and reporting Special System Tests.

DC 17.3 Procedure

DC 17.3.1 General

If the System Test proposed by the System Operator or the User connected to the Distribution System will or may have an effect on the Transmission System then the provisions of section DC 17 and the Transmission Code shall apply.

Special System Tests which have a minimal effect on the Distribution System or Systems of other Users shall not be subject to this procedure; minimal effect will be taken to mean variations in voltage, frequency and waveform distortion of a value not greater than those figures which are defined in the Distribution Planning and Interconnection section of the Codes.

DC 17.3.2 Proposal Notice

When the System Operator or a User intends to undertake a System Test which will have or may have an effect on the System or other User's Systems, normally notice shall be provided twelve (12) months in advance of the proposed System Test, or as otherwise agreed by the System Operator, by the person proposing the System Test (the Test Proposer) to the System Operator and to those Users who may be affected by such a System Test.

The proposal shall be in writing and shall contain details of the nature and purpose of the proposed System Test and shall indicate the extent and situation of the Plant or Apparatus involved.

If the information set out in the proposal notice is considered insufficient by the recipient they shall contact the Test Proposer with a written request for further information which shall be supplied as soon as reasonably practicable. The System Operator shall not be required to do anything under DC 17 until it is satisfied with the details supplied in the proposal or pursuant to a request for further information.

If the System Operator wishes to undertake a System Test the System Operator shall be deemed to have received a proposal of that System Test.

DC 17.3.3 Preliminary Notice and Establishment of Test Panel

The System Operator shall have overall co-ordination of the System Test, using the information supplied to it under section DC 17 and shall identify in its reasonable estimation, which Users other than the Test Proposer, may be affected by the proposed System Test.

DC 17.3.4 Test Panel

A Test coordinator, who shall be a suitably qualified person, shall be recommended by the Test Proposer and approved by the System Operator with the agreement of the Users which the System Operator has identified may be affected and shall act as Chairman of the Test Panel (the Test Panel).

All Users identified under DC 17 shall be given in writing, by the Test Coordinator, a preliminary notice of the proposed System Test. The preliminary notice shall contain:

a. the Test coordinator s name and nominating company;

b. the details of the nature and purpose of the proposed System Test, the extent and situation of the Plant or Apparatus involved and the Users identified by the System Operator;

c. an invitation to each identified User to nominate a suitably qualified person to be a member of the Test Panel for the proposed System Test.

The preliminary notices shall be sent within one month of the receipt of the proposal notice or the receipt of any further information requested.

As soon as possible after the expiry of this one month period all relevant Users and the Test Proposer shall be notified by the Test coordinator of the composition of the Test Panel.

A meeting of the Test Panel shall take place as soon as possible after the relevant Users and the Test Proposer have been notified of the composition of the Test Panel.

The Test Panel shall consider:

a. the details of the nature and purpose of the proposed System Test and other matters set out in the proposal notice;

b. the economic, operational and risk implications of the proposed

System Test;

a. the possibility of combining the proposed System Test with any other tests and with Plant and/or Apparatus outages which arise pursuant to the operational planning requirements of the System Operator and Users; and

b. implications of the proposed System Test on the Scheduling and Dispatch of Generating Plant, insofar as it is able to do so.

Users identified under section DC 17 and the System Operator, whether or not they are represented on the Test Panel, shall be obliged to supply that Test Panel upon written request with such details as the Test Panel reasonably requires in order to consider the proposed System Test.

The Test Panel shall be convened by the Test coordinator when it is necessary conduct its business, subject to the oversight of the System Operator.

DC 17.3.5 Proposal report

Within two months of the first meeting the Test Panel shall submit a report, which in this section DC 17 shall be called a proposal report, which shall contain:

a. proposals for carrying out the System Test (including the manner in which the System Test is to be monitored);

b. an allocation of costs (including un-anticipated costs) between the affected Parties, (the general principle being that the Test Proposer shall bear the costs); and

c. such other matters as the Test Panel consider appropriate.

The proposals report may include requirements for indemnities to be given in respect of claims and losses arising from the System Test. All System Test procedures must comply with all applicable legislation.

If the Test Panel is unable to agree unanimously on any decision in preparing its proposal report the proposed System Test shall not take place and the Test Panel shall be dissolved.

The proposal report shall be submitted to all those who received a Preliminary notice.

Within fourteen days of receipt of the proposal report, each recipient shall respond to the Test coordinator with its approval of the proposal report or its reason for non-approval.

In the event of non-approval by one or more recipients, the Test Panel shall as soon as practicable meet in order to determine whether the proposed System Test can be modified to meet the objection or objections.

If the proposed System Test cannot be so modified then the System Test shall not take place and the Test Panel shall be dissolved.

If the proposed System Test can be so modified the Test Panel shall as soon as practicable, and in any event within one month of meeting to discuss the responses to the proposal report, submit a revised proposal report.

In the event of non-approval of the revised proposal report by one or more recipients, the System Test shall not take place and the Test Panel shall be dissolved.

DC 17.3.6 Final Test Programme

If the proposal report (or, as the case may be, the revised proposal report) is approved by all recipients, the proposed System Test can proceed and at least one month prior to the date of the proposed System Test, the Test Panel shall submit to the System Operator and all recipients of the proposal notice a programme which in this section DC 17 shall be called a final test programme stating any switching sequence and proposed timings, a list of those staff involved in the carrying out of the System Test (including those responsible for site safety) and such other matters as the Test Panel deem appropriate.

The final test programme shall bind all recipients to act in accordance with the provisions contained in the programme in relation to the proposed System Test.

Any problems with the proposed System Test which arise or are anticipated after the issue of the final test programme and prior to the day of the proposed System Test must be notified to the Test Co-coordinator as soon as possible in writing If the Test coordinator decides that these anticipated problems merit an amendment to or postponement of the System Test he shall notify any party involved in the System Test accordingly.

If on the day of the proposed System Test operating conditions on the System are such that any party involved in the proposed System Test wishes to delay or cancel the start or continuance of the System Test, they shall immediately inform the Test coordinator of this decision and the reasons for it. The Test coordinator shall then postpone or cancel, as the case may be, the System.

Test and shall if possible, agree with all Parties involved in the proposed System Test another suitable time and date or if he cannot reach such agreement, shall reconvene the Test Panel as soon as practicable which shall endeavor to arrange another suitable time and date and the relevant provisions of DC 17 shall apply.

DC 17.3.7 Final report

At the conclusion of the System Test, the Test Proposer shall be responsible for preparing a written report (the final report) of the System Test for submission to other members of the Test Panel.

The final report shall include a description of the Plant and/or Apparatus, tested and of the System Test carried out, together with the results, conclusions and recommendations.

The final report shall not be distributed to any party which is not represented on the Test Panel unless the Test Panel having considered the confidentiality issues, shall have unanimously approved such distribution.

When the final report has been submitted under the Test Panel shall be dissolved.

DC 18 DISTRIBUTION METERING

DC 18.1 Purpose

To establish the requirements for metering the Active and Reactive Energy and Demand input to and/or output from the Distribution System;

a. To ensure appropriate procedures for metering reading; and

b. To ensure that procedures are in place to manage disputed readings.

DC 18.2 Scope

This sub-section applies to:

a. the System Operator

b. Users

c. Embedded Generators

d. Variable Renewable Power Plant (VRPP).

DC 18.3 Metering Requirements Embedded Generators

DC 18.3.1 Overall Accuracy

The overall accuracy of Generator metering is to be designed to give a tolerance of ±0.5% on an ongoing basis.

DC 18.3.2 Relevant Metering Policies, Standards and Specifications

Both Primary and Backup Metering systems shall be installed to accumulate the outputs and/or inputs at the High Voltage side bushing of the Generating Unit step up transformer.

The System Operator shall own and maintain the Primary Metering System while the Generator shall own and maintain the Backup Metering System.

Each meter shall have its own Current Transformer (CT) and Voltage Transformer (VT) and necessary independent Systems to function effectively.

Instrument transformers shall conform to ANSI Standards C12.11 and C57.14 Class 03 and shall have sufficient capacity to handle the attached Equipment. The ANSI standards refer to the physical characteristics of meters and the procedures and practices related to type and pattern approval. The detailed use of these standards in the testing of meters are set out in the OUR document Meter Testing Administrative Protocol which is attached at Appendix B.

The Current Transformers secondary winding used for metering purposes shall supply only the metering Equipment and associated Systems.

Notwithstanding the foregoing each Current Transformer may have other secondary windings that may be used for purposes other than metering.

Voltage Transformers' secondary windings may be used for metering and other purposes provided that the total loading does not exceed one half burden of the rating of the transformer.

DC 18.3.3 Parameters for Meter Reading

The Generator shall provide and install appropriate Equipment and shall make a continuous recording on appropriate magnetic media or equivalent of the Net Energy Output of the Generating Unit(s).

The parameters to be metered shall be subject to the Interconnection Agreement between the Generator and the System Operator, and may consist of but are not limited to any or all of the following parameters:

a. Active Energy (Wh) OUT;

b. Active Energy (Wh) IN;

c. Reactive Energy (VARh) First Quadrant;

d. Reactive Energy (VARh) Fourth Quadrant;

e. Active Power Demand (W) OUT;

f. Active Power Demand (W) IN;

g. Reactive Power Demand (VAR) First Quadrant; and

h. Reactive Power Demand (VAR) Fourth Quadrant.

All units shall be expressed at appropriate multiples determined by the maximum expected Demand.

DC 18.3.4 Frequency of Meter Reading

The Demand Interval shall be fifteen (15) minutes and shall be set to start at the beginning of the hour. Demand shall be calculated by averaging the respective parameters over the stated Demand Interval.

DC 18.3.5 Generators <100kW

For small Generators with a rated capacity below 100kW the full generator metering requirements above may be reduced. These generators shall be permitted to be metered using separate import and export meters. DC 18.3.5.2. The metering requirements for such interconnection shall have the specification and accuracy as defined in section DC 20.

DC 18.3.6 Metering Responsibility (Embedded Generators)

It is the responsibility of Embedded Generators to cooperate with the System Operator in the execution of all its responsibilities under this Code.

The costs for installation and replacement of meters shall be outlined in the Generators Power Purchase Agreement or Standard Offer Contract.

DC 18.4 Metering Requirements - Users

DC 18.4.1 Overall Accuracy

The overall accuracy of the metering for revenue purposes is to be designed to give a tolerance of ± 1% when tested in the laboratory and ± 2% when tested in the field.

DC 18.4.2 Relevant Metering Policies, Standards and Specifications

The meters, and associated installations, used on the System Operator s Distribution System shall comply with the following documents which are identified as Distribution Code Technical Specifications in DGC10.6 or issued by the OUR:

a. Licensee Engineering Instruction 4.7

b. OUR Document ELE 2005/07 Electricity Meter Testing in Jamaica - Protocol on Administrative and Testing Procedures and

c. Meter Facilities Policy as set out in Licensee Engineering Bulletin TSD 007/3

The meters shall be designed, constructed and operated to comply with the latest revision of the relevant ANSI standards or international equivalents in particular:

a. ANSI C12.1 2008 The Electric Meters code for Electricity Metering;

b. ANSI C12:10 2004 Physical aspects of watt-hour meters - safety standard; and

c. ANSI C12:20 2002 Electricity meters 0.2 and 0.5 accuracy Classes.

DC 18.4.3 Requirement for Metering

All Exit Points and Entry Points to the Distribution System shall have appropriate metering in accordance with this Distribution Metering Code.

DC 18.4.4 Metering Responsibility (Users)

It is the responsibility of the System Operator to ensure that all Exit Points and Entry Points are metered in accordance with this Code.

It is the responsibility of Users to cooperate with the System Operator in the execution of all its responsibilities under this Code.

The costs for installation and replacement of meters shall be outlined in the User's Interconnection Agreement and/or the Standard Terms and Conditions of Service.

DC 18.5 Metering Equipment

The metering Equipment shall consist of :

a. Revenue Meters;

b. Current and Voltage Transformers where applicable;

c. All interconnecting cables, wires and associated devices, seals and protection; and

d. All Equipment associated with Advanced Metering Infrastructure.

DC 18.5.1 Revenue Meters

The revenue meter shall have the appropriate rating for the interconnection requirements to be supplied and shall conform to the terms of the Interconnection Agreement between the System Operator and User/Generator.

Meters shall have an accuracy in accordance with ANSI class 0.5 or international equivalent.

At the System Operator s discretion Advanced Metering Infrastructure may be installed at some Customers sites. This metering infrastructure enables two way communication with the metering Systems. These devices shall comply with the specifications in DC 16.2.2. The accuracy shall be equivalent to ANSI Class 0.5.

The relevant metered parameters, as required by the System Operator for billing purposes, shall be stored cumulatively on the meter and shall be able to be accessed by the User Generator.

Where required these parameters may include any or all of the following depending on the interconnection and the tariff schedule:

a. KW Hours (delivered and received);

b. KVAr Hours (delivered and received);

c. KVA Hours (delivered and received);

d. Ampere Squared Hours

e. Volt Squared Hours

f. Maximum Demand (15 minute period)

g. Power Factor

The above parameters shall be measurable over intervals from 1 minute to 60 minutes.

DC 18.5.2 Voltage Transformers

All Voltage Transformers shall comply with IEC Standards or their equivalents and shall have and accuracy class of 0.5.

The burden in each phase of the Voltage Transformer shall not exceed the specified burden of the said Voltage Transformer.

DC 18.5.3 Current Transformers

All Current Transformers shall comply with IEC Standards or their equivalents and shall have and accuracy class of 0.5.

The burden in each phase of the Current Transformer shall not exceed the specified burden specification of the said Current Transformer.

DC 18.6 Metering Points

DC 18.6.1 Whole Current Metering

The Metering Point should be as close as possible to the Interconnection Point.

CT Metering

The Metering Point shall be at the position of the Current Transformers used for the metering system. This should be designed to be as close as possible to the Interconnection Point.

Current Transformers should be installed in a separate chamber and must be before the main switch (on the line side). They shall be housed in suitable metal enclosures, and be able to be secured.

Where the Interconnection Point is declared on the outgoing side of a High voltage circuit breaker the metering Current Transformers may be accommodated in that circuit breaker unit.

Where appropriate the Metering Point should be at the same voltage as the Interconnection Point. Where the Metering Point is at a lower voltage than the Interconnection Point then appropriate loss factors should be calculated to ensure any additional loss is appropriately accounted for.

DC 18.7 Meter Reading and Collection Systems

DC 18.7.1 Meter Reading and Recording Responsibility

It is the responsibility of the System Operator to ensure that meters are read in accordance with the requirements of overall standard EOS7 in the System Operators Licence.

Meter reading and recording shall be undertaken by a suitable authorized representative of the System Operator.

It is the responsibility of Users and Embedded Generators to cooperate with the System Operator in the execution of its responsibilities under this Code.

The User shall be provided with access to its billing and consumption records on request.

DC 18.7.2 Approval of Meters

Only meters that have received pattern approval from the Bureau of Standards, Jamaica (BSJ) in accordance with the OUR Document ELE 2005/07 Electricity Meter Testing in Jamaica - Protocol on Administrative and Testing Procedures, may be used on the System Operators Distribution System.

DC 18.8 Calibration and Sealing

DC 18.8.1 Calibration

All meters (new meters and repaired meters) rated above 12kVA shall be calibrated and the tolerance adjusted to ensure that it measures as close to zero tolerance as possible prior to field installation.

All meters rated above 12kVA shall be recalibrated every 10 years where unless they have a manufacturers guaranteed calibration period in which case this period shall be used.

All meters rated at 12kVA and below shall comply with the requirements of acceptance testing in OUR Document ELE 2005/07 Electricity Meter Testing in Jamaica - Protocol on Administrative and Testing Procedures, prior to field installation.

All laboratory calibration shall be undertaken in laboratories accredited by JANAAC.

DC 18.8.2 Traceability

The kilowatt hour standard used to calibrate electricity meters shall be traceable to the Systeme Internationale (SI) at the Bureau Internationale des Pois et Measures. This extends to the calibration of Equipment used to calibrate meters.

DC 18.8.3 Sealing

All meters shall be constructed to enable the meter unit to be sealed to prevent unauthorized access or interference with the Operation of the meter or the input terminals of the meter.

All meters shall be sealed to prevent unauthorized access or interference with the Operation of the meter or the input terminals of the meter.

Seals applied after calibration shall be marked with the date that recalibration is required.

All seals shall include marks that identify the authorized person that sealed the meter.

DC 18.9 Metering Disputes

DC 18.9.1 Meter Accuracy Check

A User/Embedded Generator has a right to request a meter accuracy check when they consider that the meter may be reading incorrectly in accordance with the meter testing protocol.

Should a User/Embedded Generator request more than one accuracy check in a single calendar year then the System Operator may charge for these additional check should the accuracy be within ± 2%?

DC 18.9.2 Resolution of Disputes

If the metering system is found to be inaccurate by more than the allowable error and the System Operator and the Generator/User fail to agree upon an estimate for the correct reading within a reasonable time (as specified in the relevant Power Purchase Agreement or Interconnection Agreement or Standard Offer Contract) of the Dispute being raised, then the matter may be referred for arbitration by either party in accordance within the relevant specified agreements.

DC 18.10 Inspection and Testing

DC 18.10.1 Maintenance Policy

The System Operator shall put in place and implement a policy for the inspection and testing and recalibration of all metering Equipment. This policy shall be in accordance with the procedures set out in DC 16.2 above.

DC 18.10.2 Maintenance Records

The System Operator shall keep all test results, maintenance programme records and sealing records for a period of at least 5 years.

DC 18.10.3 Generator Metering

The System Operator and Generator shall abide by the conditions of the Generation Code that details the maintenance procedures to be applied in the case of Generator meters. The Generation Code includes provisions on the use of back-up meters when metering inaccuracies are suspected and on the resolution of metering Disputes.

DC 19 DISTRIBUTION DATA REGISTRATION

DC 19.1 General

Where there is any inconsistency in the data requirements under any particular section of the Distribution Code and the Data Registration Code the provisions of the particular section of the Distribution Code shall prevail.

The Code under which any item of data is required specifies the procedures and timing for the supply of data, for routine updating and for recording temporary or permanent changes to data.

The DRC also lists data required to be provided by Generators under the Generation Code.

DC 19.2 Objective

The objective of the Data Registration section of the Code is to:

a. List and collate all the data to be provided by each category of User to the System Operator under the Distribution Code;

b. List all data to be provided by the System Operator to each category of User under the Distribution Code; and

c. List all data to be provided by Generators to the System Operator and by the System Operator to Generators under the terms of the Generation Code.

DC 19.3 Scope

The Users to which the DR section of this Code applies are:

a. Generators under the terms of the Generation Code;

b. Licensee in its role as System Operator; and

c. Users connected directly to the Distribution System.

DC 19.4 Data Categories and Stages in Registration

DC 19.4.1 General

Within the Data Registration Requirements each item of data is allocated to three categories.

a. System Planning Data as required by the Planning and Interconnection section of the Distribution Code;

b. Generation Planning Data as required by the Generation Code;

c. Operational Data as required by the System Operator. This section also includes data required from Generators in accordance with the Scheduling and Dispatch provisions of the Generation Code.

DC 19.5 Procedures and Responsibilities

DC 19.5.1 Responsibility for Submission and Updating of Data

In accordance with the provisions of the various Chapters of the Distribution Code, each User must submit data as summarized, listed and collated in the attached Schedules.

DC 19.5.2 Methods of Submitting Data

The data must be submitted to the System Operator. The name of the person at the User who is submitting each Schedule of data must be included. The data may be submitted via a computer link if such a data link exists between a User and the System Operator or utilizing a data transfer media, such as USB drive, CD ROM, Cloud technology, etc. after obtaining the prior written consent from the System Operator.

DC 19.5.3 Changes to Users Data

The User must notify the System Operator of any change to data which is already submitted and registered with the System Operator in accordance with each section of the Distribution Code.

DC 19.5.4 Data not supplied

If a User fails to supply data when required by any section of the Distribution Code, the System Operator shall estimate such data if and when, in the view of the System Operator, it is necessary to do so.

If the System Operator fails to supply data when required by any section of the Distribution Code, the User to whom that data ought to have been supplied, shall estimate such data if and when, in the view of that User, it is necessary to do so.

Such estimates shall, in each case be based upon data supplied previously for the same Plant or Apparatus or upon corresponding data for similar Plant and/or Apparatus or upon such other information as the System Operator or that User, as the case may be, deems appropriate.

The System Operator shall advise a User in writing of any estimated data it intends to use relating directly to that User Plant and/or Apparatus in the event of data not being supplied.

The User shall advise the System Operator in writing of any estimated data it intends to use in the event of data not being supplied.

Schedule	Data Type	Description	User	Code section	Licensee Procedure
I	User System Data	Electrical parameters relating to Plant and Apparatus connected to the Distribution System	Licensee	DC 5.3 DC 5.3.1 DC 5.3.2 DC 8.3	EI 3.1 SOPP 4 SOPP 7 SOPP 9
II	Load Characteristics	The estimated parameters of loads in respect of, for example, harmonic content, frequency response.	Licensee	DC 3.3.2 DC 3.7 DC 3.8.1 DC 3.8.3	
III	Demand profiles and Active Energy	Total Demand and Active Energy taken from the Distribution System	Licensee	DC 3.3 DC 3.7 DC 5.3 DC 3.7.2 DSC 3 DSC 6	
IV	Interconnection Point	Information related to Demand, and a summary of Embedded Generators and Customer generation	Licensee	DC 3.3.2 DC 3.7 DC 3.8.1 DC 3.8.2	

		connected to the Interconnection Point.		DC 3.8.3 DC 4	
V	Demand Control	Information related to Demand Control	Licensee User	DC 11 GC 8 DSC 3	EI 1.6 SOPP 11
VI	Fault Infeed	Information on Short Circuit contribution to the Distribution System.	Licensee User GEN	DC 3.6.5 DC 3.7	

Abbreviations used in all Schedules:	
GEN	Generator
GC	Generation Code
DC	Transmission Code
TC	Dispatch Code
DSC	Licensee Engineering Instructions
EI	Licensee System Operation Policies and Procedures
SOPP	

NOTE: In the Schedules Data Category refers to the Code Sections and/or Licensee Instructions/Procedures.

SCHEDULE I: USERS SYSTEM DATA

The data in this Schedule I is required from all Users with appropriate Demand at the discretion of the System Operator.

Data Description	Units	Code section	Licensee Instruction/ Procedure
Operation Line Diagram **Single Line Diagram showing all existing and proposed** **Equipment and Apparatus and Interconnections together with Equipment rating**	Drawing	DC 5.3.2	SOPP 9
Site Responsibility Schedules	Schedule	DC 8.3	
Safety Coordinators	Text	DSC 12.2	
Reactive Compensation Equipment		DC 7.3	SOPP 4 SOPP 7
For all reactive compensation Equipment connected to the User System at [12kV] and above, other than Power **Factor correction Equipment associated directly with a** **Customer Plant, the following details** **Type of Equipment (e.g. fixed or variable)**	Text		
Capacitive rating	MVAr		
Inductive rating	MVAr		
Operating range	MVAr		
Details of any automatic control logic to enable operating characteristics to be determined	Text and/or Diagrams		
Point of Interconnection to the User System in terms of electrical location and System voltage	Text		
Switchgear		DC 5.3.2	SOPP 7

For all switchgear (i.e. circuit breakers, switch disconnectors and isolators) on all circuits Directly Connected to the Interconnection Point including those at Production Facilities Rated voltage	kV		
Operating voltage	kV		
Rated short-circuit breaking current single phase Three phase	kA		
Rated load breaking current single phase Three phase	kA		
Rated peak short-circuit making current single phase Three phase	kA		
User Connecting System data: Circuit Parameters for all circuits		DC 5.3.2	SOPP 7
For all Systems at [12] kV and above Connecting User System to the Distribution System, the following details are required relating to that Interconnection Point Rated voltage	kV		
Operating voltage	kV		
Positive phase sequence Resistance Reactance Susceptance	 % on 100 % on 100 % on 100		
Zero phase sequence Resistance	 % on 100		

Reactance **Susceptance**	% on 100 % on 100		
Interconnecting transformers		DC 5.3.2	SOPP 7 EI 3.1
For transformers between the Distribution System and the User System, the following data is required: **Rated Power** **Rated Voltage Ratio** **(i.e. primary/secondary/tertiary)** **Winding arrangement** **Vector group**	MVA		
Positive sequence resistance **@ maximum tap** **@ minimum tap** **@ nominal tap**	 % on MVA % on MVA % on MVA		
Positive sequence reactance **@ maximum tap** **@ minimum tap** **@ nominal tap**	 % on MVA % on MVA % on MVA		
Zero phase sequence reactance	% on MVA		
Tap changer type **Tap changer range** **Tap changer step size** **Impedance value (if not directly earthed)**	On/Off		
MV Motor Drives			
Following details are required for each MV motor drive	MVA	DC 5.3.2	SOPP 7

connected to the User System Rated VA			
Rated Active Power	MW		
Full Load Current	kA		
Means of starting	Text		
Starting Current	kA		
Motor torque/speed characteristics **Drive torque/speed characteristics** **Motor plus drive inertia constant**			
User Protection Data		DC 5.3.2	SOPP 7
Following details relates only to protection Equipment which can trip, inter-trip or close any Interconnection Point circuit breaker or any System Operator circuit breaker A full description including estimated settings, for all relays and Protection Systems installed or to be installed on the User System	Test		
A full description of any auto-reclose facilities installed on the User System, including type and time delays	Text		
The most probable fault clearance time for electrical faults on any part of the User System Directly Connected to the Distribution System	Ms		
Transient Over-Voltage Assessment Data		DC 5.3.2	SOPP 7
When requested by Licensee, each User is required to submit data with respect to the Interconnection Site as follows (undertaking insulation co-ordination studies) Bus bar layout, including dimensions and geometry together with electrical parameters of any associated Current Transformers, Voltage Transformers, wall bushings, and support insulators	Diagram		
Physical and electrical parameters of lines, cables, transformers, reactors and shunt compensator Equipment Connected at that bus bar or by lines or cables to the bus bar (for the purpose of calculating surge impedances)	Text		

Specification details of connected directly or by lines and cables to the bus bar including basic insulation levels	Text
Characteristics of over-voltage protection at the bus bar and at the termination of lines and cables connected at the bus bar	Text

SCHEDULE II: LOAD CHARACTERISTICS

The following information is required from each User with appropriate Demand, at the discretion of the System Operator, regarding existing and future interconnections for each Interconnection Point.

Description	Units	Data for Future Years				Data category
		Year 1	Year 2	Year 3	Year 4	
1. Details of individual loads which have fluctuating, pulsing or other characteristics significantly different from the typical range of Domestic, Commercial or Industrial loads supplied						DC 3.8.3
2. Sensitivity of Demand to variations in voltage and frequency on the Distribution System at the peak Interconnection Point Demand (Active Power) o Voltage sensitivity	M W/kV MVAr/kV MW/Hz MVAr/Hz					
- Frequency sensitivity						
3. Phase unbalance imposed on the Distribution System **- Maximum**	%					
- Average						
4. Maximum harmonic content imposed on the Distribution System						
5. Details of loads which may cause Demand fluctuations greater than [1 MW] at an Interconnection Point						

SCHEDULE III: DEMAND PROFILES AND ACTIVE ENERGY DATA

The following information is required from each Users with appropriate Demand, at the discretion of the System Operator.

Data Description	FY0	FY1	FY2	Update Time	Data Category
Forecast daily Demand profiles in respect of each User System (summated over all Interconnection Points)	1. Day of User maximum Demand (MW) at Annual MD Conditions 2. Day of peak Distribution System Demand (MW) at Annual MD Conditions 3. Day of minimum Distribution System Demand (MW) at Average Conditions (Delete as appropriate)			End January	DC 3.8.1 DC 5.3.2 DC 3.7.2
0000 : 0100					
0100 : 0200					
0200 : 0300					
0300 : 0400					
0400 : 0500					
0500 : 0600					
0600 : 0700					
0700 : 0800					
0800 : 0900					
1000 : 1100					
1100 : 1200					
1200 : 1300					
1300 : 1400					
1400 : 1500					

1500 : 1600 **1600 : 1700** **1700 : 1800** **1800 : 1900** **1900 : 2000** **2000 : 2100** **2100 : 2200** **2200 : 2300** **2300 : 2400**		
The annual MWh requirements for each User System (summated over all Interconnection Points for the Distribution System) at Average Conditions: **1. Domestic** **2. Agricultural** **3. Commercial** **4. Industrial** **5. Parish** **6. Public Lighting** **7. [Any other identifiable categories of** **Generator]** **8. User System losses**	End Sept	DC 3.8.1 DC 5.3.2
Applicable only Users with Embedded Generators **1. Total Demand (MW) on its System**	End Sept	DC 3.8.1 DC 4 DC 5.4

2. Active Energy (MWh) requirement on its System

3. Active Energy from Embedded Generation

SCHEDULE IV INTERCONNECTION POINT DATA

The following information is required from each User with appropriate Demand, at the discretion of the System Operator.

Data Description	Units	YR 0	YR 1	YR 2	Update Time	Data Category
Forecast Demand and Power Factor related to each Interconnection Point **1. Annual peak hour User MW** **Demand at Annual MD pf** **Conditions** **2. User Demand at Distribution MW System peak hour Demand pf** **at Annual MD Conditions** **3. User Demand at minimum MW hour Distribution System pf** **Demand at Average Conditions**	MW				End Sept	DC 3.8.1 DC 3.8.3 DC 3.8.1 DC 3.8.3 DC 3.8.1 DC 3.8.3
Demand Transfer Capability **Where a User Demand or group of Demands may be fed by alternative Interconnection Point(s) , the following details should be provided:** **1. Name of the alternative Interconnection Point(s)** **2. Demand transferred** **3. Transfer arrangement** **(e.g. manual or automatic)**	MW MVAr hrs				End Sept	DC 3.8.1 DC 3.8.3

4. Time to effect transfer

SCHEDULE V: DEMAND CONTROL DATA

The following information is required from the System Operator or Embedded Customer

Data Description	Units	Time Covered	Update Time	Data Category
Programming Phase: applicable to the System Operator and Embedded Generator				
Demand Control which may result in a Demand change of [1] MW or more on an hourly and Interconnection Point basis	MW	Weeks 1 to 8	10:00 Friday	DC 11 EI 1.6
1. Demand profile				SOPP 11
2. Duration of proposed Demand Control	Hrs.	Weeks 1 to 8	10:00 Friday	DSC 3 DSC 6
Control Phase: applicable to Distribution System Operator and Non-Embedded Generator				
1. Demand Control which may result in a Demand change of 1 MW or more averaged over any hour on any Interconnection Supply Point which is planned after 10:00 hours	MW	Now to 7 Days	mediate	DC 11
2. Any changes to planned Demand Control notified to the System Operator prior to 10:00 hours	Hrs.	Now to 7 Days	mediate	
Post Control Phase				
Demand reduction achieved on previous calendar day of 1 MW or more averaged over any Interconnection Point, on an hourly and Interconnection				DC 11
1. Active Power profiles	MW	Previous Day	10:00 Daily	
2. Duration	Hrs.	Previous Day	10:00 Daily	

SCHEDULE VI: FAULT INFEED DATA

The following information is required from each User who is connected to the Distribution System via an Interconnection Point where the User System contains Embedded Generating Unit(s) and/or motor loads. The data is required for the three following years

Data Description	Units	Update Time	Data Category
Short Circuit Infeed to Distribution System from User System at an Interconnection Point			
Name of Interconnection Point: ______________________________			
1. Symmetrical three-phase short circuit current infeed:		[end Sept]	DC 3.7
o At instant of fault	kA		
o After sub-transient fault current contribution has substantially	kA		
2. Zero sequence source impedance values as seen from the Interconnection Point consistent with the maximum infeed above: **o Resistance (R)**	% on 100		
o Reactance (X) **3. Positive sequence X/R ratio at instant of fault**	% on 100		

SCHEDULE VII USER OUTAGES DATA

Data Description	Timescale Covered	Update Time	Data Category
Generators and Non-Embedded Generator provide **Details of Apparatus owned by them other than** **Generating Units at each Interconnection Point**	Year 1	[end Sept]	
System Operator informs Users of aspects that may affect their Systems	Year 1		
Users inform System Operator if not in agreement with aspects as notified	Year 1		
System Operator issues final Transmission System outage plan with advice on Operational Effects on User Systems	Year 1	[end Oct]	DC 3.3
Embedded Generator and Users to inform System **Operator of changes to outages previously requested**	Week 8 ahead to year end	As occurring	DC 3.3

Transmission Code is referenced as the final outage plan rests with Transmission.

DC APPENDIX A

Site Responsibility Schedules

At all Interconnection Sites the following Site Responsibility Schedules shall be drawn up using the pro-forma attached or with such variations as may be agreed between the System Operator and Users, and in the absence of agreement the pro-forma attached shall be used: i) Schedule of MV Apparatus ii) Schedule of Plant, LV Apparatus, services and supplies; iii) Schedule of telecommunications and measurements Apparatus.

Other than at Generating Unit and Power Station locations, the schedules referred to in (ii) and (iii) above may be combined.

Each Site Responsibility Schedule for an Interconnection Site shall be prepared by the System Operator in consultation with other Users at least 2 weeks prior to the Completion Date under the Interconnection Agreement for that Interconnection Site. Each User shall, in accordance with the timing requirements of the Interconnection Agreement, provide information to the System Operator to enable it to prepare the Site Responsibility Schedule.

Each Site Responsibility Schedule shall detail for each item of Plant and Apparatus;

i. Item of Equipment using the agreed Numbering and Nomenclature in accordance with section DC 15.

ii. Equipment Owner - This identifies the party that owns the Equipment under common law;

iii. Safety Rules - This identifies whether the System Operator s or User's Safety Rules shall be applied to the Equipment.

iv. Operational Procedures - This identifies whether System Operator or Users personnel shall be responsible for Operations on the Equipment. Note that if this is System Operator, it does not preclude the System Operator from authorizing Users personnel from acting on its behalf and vice versa.

v. Control responsibility - This identifies whether the System Control used shall be the System Operators or the Users.

vi. Maintenance responsibility - This identifies whether the System Operator or the User is responsible for the inspection and maintenance of the Equipment.

vii. Access and security. This identifies whether the System Operator or the User shall be responsible for the establishment and maintenance of perimeter fencing and any manned access security for the protection of the public and to prevent malicious entry. Access to operational areas of the site shall be restricted to persons duly authorized in accordance with the prevailing Safety Rules.

The MV Apparatus Site Responsibility Schedule for each Interconnection Site must include lines and cables emanating from the Interconnection Site.

Every page of each Site Responsibility Schedule shall bear the date of issue and the issue number.

When a Site Responsibility Schedule is prepared it shall be sent by System Operator to the Users involved for confirmation of its accuracy.

The Site Responsibility Schedule shall then be signed on behalf of System Operator by the Manager responsible for the area in which the Interconnection Site is situated and on behalf of each User involved by its Responsible Manager, by way of written confirmation of its accuracy. Once signed, two copies shall be distributed by System Operator, not less than two weeks prior to its implementation date, to each User which is a party on the Site

Responsibility Schedule, accompanied by a note indicating the issue number and the date of implementation.

ATTACHMENT TO APPENDIX A: PRO FORMA FOR SITE RESPONSIBILITY SCHEDULE

Signed on behalf of the System Operator Date:

Signed on behalf of the User

Item of Equipment	Equipment Owner	Property Rules	Operational Responsibility	Control Responsibility	Maintenance Responsibility	Access and Security	Comments

DC APPENDIX B

TECHNICAL REQUIREMENTS FOR UNDER FREQUENCY RELAYS

The Interconnection Agreement shall specify the manner in which Demand at the User Site, subject to Automatic Load Disconnection (separate from the System Operators under frequency load shedding scheme), shall be actuated by under-frequency relays.

1. Under Frequency Relays shall have a frequency setting range of 46.0 to 52.0Hz and be suitable for Operation from a nominal AC input of 63.5, 110 or 240V.

The following general parameters on the requirements of approved Frequency Relays for automatic installations is given as an indication to the provisions that may be included in a Interconnection Agreement:

   a. Frequency settings: 46-52Hz in steps of 0.01Hz;

   b. Measurement period: Within a minimum selectable settings range of 3 to 7 cycles;

   c. Operating time: Between 100 and 160ms dependent on measurement period setting;

   d. Voltage lock-out: 20 to 90% of nominal voltage;

   e. Facility stages: Four stages of frequency Operation;

   f. Output contacts: Two output contacts per stage.

2. The voltage supply to the Under Frequency Relays shall be derived from the Transmission System at the supply point concerned so that the frequency of the Under Frequency Relays input voltage is the same as that of the primary System. This requires either:

   a. the use of a secure supply obtained from Voltage Transformers directly associated with the Transmission System interconnection transformer(s) concerned, the supply being obtained where necessary via a suitable automatic voltage selection scheme; or

   b. the use of the substation 110V phase-to-neutral selected auxiliary supply, provided that this supply is always derived at the Interconnection Point concerned and is never derived from a standby Generator or from another part of the User System.

The tripping facility should be engineered in accordance with the following reliability considerations:

1. Dependability: Failure to trip at any one particular Demand shedding point shall not harm the overall Operation of the scheme. However, many failures would have the effect of reducing the amount of Demand under low frequency control.

2. Outages: Low frequency Demand shedding schemes shall be engineered such that the amount of Demand under control is as specified by the System Operator and is not reduced unacceptably during Equipment outage or maintenance conditions.

DC APPENDIX C

PROCEDURES RELATING TO OPERATION DIAGRAMS

Basic Principles

Where practicable, all the MV Apparatus on any Interconnection Site shall be shown on one Operation Diagram. Provided the clarity of the diagram is not impaired, the layout shall represent as closely as possible the geographical arrangement on the Interconnection Site.

1. Where more than one Operation Diagram is unavoidable, duplication of identical information on more than one Operation Diagram must be avoided.

2. The Operation Diagram must show accurately the current status of the Apparatus, e.g. whether commissioned or decommissioned. Where decommissioned, the associated switch bay shall be labelled "spare bay".

3. Provision shall be made on the Operation Diagram for signifying approvals, together with provision for details of revisions and dates.

Apparatus to be shown on Ownership Diagrams

1. Bus bars
2. Circuit Breakers
3. Disconnector (Isolator) and Switch Disconnectors (Switching Isolators)
4. Disconnectors (Isolators) - Automatic Facilities
5. Bypass Facilities
6. Earthing Switches
7. Maintenance Earths
8. Overhead Line Entries
9. Overhead Line Traps
10. Cable and Cable Sealing Ends
11. Generating Unit
12. Generator Transformers
13. Generating Unit Step Up Transformers, Station Transformers, including the lower voltage circuit-breakers

14. Synchronous Compensators
15. Static VAR Compensators
16. Capacitors (including Harmonic Filters)
17. Series or Shunt Reactors
18. System Transformers
19. Tertiary Windings
20. Earthing and Auxiliary Transformers
21. Three Phase VTs
22. Single Phase VT & Phase Identity
23. High Accuracy VT and Phase Identity
24. Surge Arrestors/Diverters
25. Neutral Earthing Arrangements on MV Plant
26. Fault Throwing Devices
27. Quadrature Boosters
28. Arc Suppression Coils
29. Current Transformers (where separate Plant items)
30. Wall Bushings

Use of Approved Graphical Symbols

All graphical symbols to be used in Operation Diagrams shall be approved by the System Operator.

DC APPENDIX D - SCADA INTERFACING

This Appendix sets out the technical requirements for connections to the Grid Operator’s Supervisory Control and Data Acquisition System outstation in terms of electrical characteristics.

GENERAL REQUIREMENTS

In all cases signals shall be arranged such that the level of electrical interference does not exceed those defined in IEC 870-2-1: "Telecontrol Equipment and Systems - Operating Conditions - Power Supply and Electromagnetic Compatibility" and IEC870-3: "Telecontrol Equipment and Systems - Specification for Interfaces (Electrical Characteristics)".

Digital Inputs

Digital inputs cover both single and double points for connection to digital input modules on the Grid Operators outstation Equipment. The Equipment contacts shall be free of potential, whereas the input circuitry of the outstation are common to the negative 48 volt potential.

Single Points

Single point inputs must be used for alarms and where single contact indications are available. The off (contact open or 0) state is considered to be the normal state and the on (contact closed or 1) state the alarm condition.

Double Points

Double points are used to indicate primary Plant states by the use of complementary inputs for each Plant item. Only the "10" and "01" states are considered valid with the "00" and "11" states considered invalid. The "10" state is considered to be the normal or closed state.

Energy Meter Inputs

Energy meter input pulses for connection to pulse counting input modules on the Grid Operator’s outstation Equipment must operate for a minimum of 100ms to indicate a predetermined flow of MWh or MVArh. The contact must open again for a minimum of 100ms. The normal state of the input must be open.

Analogue Inputs

Analogue inputs for connection to analogue input modules on the Grid Operator’s outstation Equipment must all be electrically isolated with a two wire connection required. Signals shall be in the form of 4-20mA (or other range to be agreed between the User and the Grid Operator) for both unidirectional and bi-directional measured values. Signal converters shall be provided as necessary to produce the correct input signals.

Command Outputs

All command outputs for connection to command output modules on the Grid Operator's outstation Equipment switch both the 0 volts and -48 volts for a period of 2.5 seconds at a maximum current of 1 amp. All outputs shall electrically isolated with a two wire connection to control interposing relays on the Plant to be operated.

Despatch Code

DSC

DSC 1 INTRODUCTION

Fuel cost is one of the most significant components of electricity cost. The efficient use of fuel is imperative to driving electricity prices down. Economic load dispatch is a necessary tool to assist in the minimization of generation cost.

Scheduling the operations of Generating Units to produce energy at the lowest cost to reliably serve consumers, taking into account any operational limits of generation and transmission facilities, the possibility of generator and transmission outages (contingencies) is a major component of operations planning.

The Scheduling of the Generating Units depends upon the System load demand profile, the Least Cost operation of System, the availability, parameters and variable operating costs of Generating Units, the flexibility of operation of Generating Units, constraints on the Transmission System, security requirements, and System losses.

DSC 1.1 Objective

The objectives of the Despatch Code are:

a. to set out roles, responsibilities and process for the Despatch of Generation and demand-side resources in meeting the electricity demand at Least Cost subject to operating constraints and system security;

b. to enable the SO to coordinate maintenance outages as far as possible in advance to allow the SO to maintain system security and reliability; and

c. to ensure fair and equitable treatment of all generator operators connected to the SO grid.

The Despatch Code sets out the procedures for:

a. the daily notification by the Generators of the Availability of any of their CDGU in an Availability Declaration;

b. the daily notification of whether there is any CDGU which differs from the last Generating Unit Scheduling and Despatch Parameters (SDP), in respect of the following Schedule Day by each Generator in a SDP Notice;

c. the submission of certain network data by each User directly connected to the Transmission System to which Generating Units are connected (to allow consideration of Network constraints);

d. the submission of certain network data by Users directly connected to the Distribution to which Generating Units are connected (to allow consideration of distribution restrictions); and

e. the production of a Least Cost Generation Schedule which schedule, for the avoidance of doubt, in this Despatch Code means unit commitment and generation Despatch level.

DSC 1.2 Structure of the Despatch Code

The Despatch Code consists of the following Sections;

SECTION 1	INTRODUCTION TO THE CODE
SECTION 2	CONFIDENTIALITY
SECTION 3	SHORT TERM OPERATIONAL PLANNING
SECTION 4	OPERATING MARGIN
SECTION 5	MERIT ORDER SYSTEM
SECTION 6	UNIT COMMITMENT SCHEDULING AND DISPATCH
SECTION 7	SCADA SYSTEM UPDATE
SECTION 8	INSTRUCTION TO SYNCHRONIZE / DESYNCHRONIZE
SECTION 9	FREQUENCY AND VOLTAGE CONTROL
SECTION 10	OPERATING RESERVE MONITORING AND MANAGEMENT
SECTION 11	DISPATCH DEVIATION TRACKING AND REPORTING
SECTION 12	SAFETY CO-ORDINATION
SECTION 13	CONTINGENCY PLANNING
SECTION 14	INCIDENT INFORMATION SUPPLY
SECTION 15	METERING AND DATA ACQUISITION
SECTION 16	DATA TO BE EXCHANGED BETWEEN THE SYSTEM OPERATOR AND GENERATORS
SECTION 17	DATA SCHEDULES

DSC 1.3 Scope

This Despatch Code applies to the System Operator and Single Buyer, and to the following Users:

a. Generators with a Centrally Despatched Generating Unit (s);

b. Users connected directly to the Transmission System.

c. Users connected directly to the Distribution System.

d. Directly Connected Customers who can provide Demand Reduction in real time.

DSC 1.4 Roles and Responsibilities

DSC 1.4.1 The OUR

a. OUR shall be responsible for monitoring and enforcement of:

i. the application of the Despatch Code by the SO;

ii. compliance of Generators to the Despatch (via their licences); and

iii. Handling of disputes between participants in accordance with Dispute Resolution provision of the Code.

DSC 1.4.2 The System Operator

a. The SO shall;

i. apply the Despatch Code;

ii. Schedule and Despatch generation and demand-side resources to least cost whilst maintaining the prescribed system security

iii. provide regular reports to the OUR and the Minister responsible for electricity prescribed in section 10 regarding the scheduling and Despatch of the System;

iv. maintain data for the auditing of the Despatch function;

v. disclose to participants upon request the reasons for Despatch instructions; and

vi. monitor and enforce compliance of demand-side resources to the Despatch Code (via their customer agreements reserved).

b. Under operating conditions where available generation capacity and demand side resources are insufficient to meet the demand, the SO may take actions that may not be in line with the Despatch Code.

c. Under normal operating conditions any contractual requirements that restrict Despatch instructions from the SO shall apply. Under emergency operating conditions the SO may override these contractual requirements and enforce Despatch instructions on all Generators, provided that the generator is able to comply with SO instruction within statutory limits.

DSC 1.4.3 Generators

a. A Generator shall take into consideration all prevailing constraints, technical and/or economical, prior to submitting information required under the Despatch Code.

DSC 2 CONFIDENTIALITY

All information provided to the System Operator marked as "Confidential" shall be treated in accordance with Licence Condition 7.

DSC 3 SHORT TERM OPERATIONAL PLANNING FOR DESPATCH

The Short Term Despatch Operations Planning is concerned with:

a. Despatch Data Registration;

b. Demand Forecasting;

c. Operational Planning and Data Provision;

d. Operating Margin;

e. Safety Co-ordination;

f. Heat Rate Policy (Development and Testing Schedule); and

g. Despatcher Training (Simulator setup and use).

DSC 3.1 DESPATCH DATA REGISTRATION (DDR)

DSC 3.1.1 Introduction

The Data Registration sets out a unified listing of all data required by the System Operator from Generators and by Generators from the System Operator for Despatch.

The Code specifies the procedures and timing for the supply of data, for routine updating and for recording temporary or permanent changes to data.

DSC 3.1.2 Objective

The objective of the DDR is to:

List and collate all the data to be provided by each category of Generator to the System Operator under the Despatch Code;

List all data to be provided by the System Operator to each category of Generator under the Despatch Code.

DSC 3.1.3 Scope

The Users to which the DDR applies are:

Generators under the terms of the Generation Code;

DSC 3.1.4 Data categories and stages in registration

Within the Data Categories and Stages in Registration each item of data is allocated to four categories.

Operational Data as required by the Despatch Code.

Data Required for Demand Forecasting

Data required from Generators in accordance with the Merit Order provisions of the Generation Code.

Design Data for Generator modelling for system simulations

DSC 3.2 Procedures and Responsibilities

DSC 3.2.1 Responsibility for submission and updating of data

In accordance with the provisions of the various sections of the Despatch Code, each Generator must submit data as summarized, listed and collated in the attached Schedules.

DSC 3.2.2 Methods of submitting data

The data must be submitted to the System Operator. The name of the personat the Generator who is submitting each Schedule of data must be included.

The data may be submitted via a computer link if such a data link exists a Generator and the System Operator or utilizing a data transfer media, such as USB drive, CD ROM, Cloud technology etc. after obtaining the prior written consent from the System Operator.

DSC 3.2.3 Changes to Generators' data

The Generator must notify the System Operator of any change to data which is already submitted and registered with the System Operator in accordance with each section of the Despatch Code.

DSC 3.2.4 Data not supplied

If a Generator fails to supply data when required by any Section of the Despatch Code, the System Operator will estimate such data if and when, in the view of the System Operator, it is necessary to do so.

If the System Operator fails to supply data when required by any Section of the Despatch Code, the Generator to whom that data ought to have been supplied, will estimate such data if and when, in the view of that Generator, it is necessary to do so.

Such estimates will, in each case be based upon data supplied previously for the same Plant or Apparatus or upon corresponding data for similar Plant and/or Apparatus or upon such other information as the System Operator or that Generator, as the case may be, deems appropriate.

The System Operator will advise a Generator in writing of any estimated data it intends to use relating directly to that Generator's Plant and/or Apparatus in the event of data not being supplied.

The Generator will advise the System Operator in writing of any estimated data it intends to use in the event of data not being supplied.

DSC 3.3 Demand Forecast

DSC 3.3.1 Introduction

In order for the System Operator to operate the System efficiently and to ensure maximum System Security and System Stability, there is a need for Users and Generators specified to provide Demand and generation output information to the System Operator.

The Despatch Code specifies the System Operator's requirements for forecasting for Generating Units subject to Central Despatch and large demand on connected to the transmission system. This Section specifies the information to be provided by all Generators and Users of the System to the System Operator so these requirements can be met.

The information to be provided under this Section is required to enable the System Operator to maintain the integrity of the System.

Where Demand data is required from the Users. this means the Active (MW)

Demand for electricity at the respective Interconnection Point with the Users. The System Operator may, in certain cases, specify that the Demand data shall include the Reactive (MVAr) Demand.

The information to be provided to the System Operator shall be in writing.

References to data to be supplied on an hourly basis refers to it being supplied for each period of 60 minutes ending on the hour in each day.

DSC 3.3.2 Objective

This section applies to the System Operator and the following Generators and Users:

Despatchable and Non-Despatchable Generators;

Users connected directly to the Transmission System.

The objectives of section DSC 3.2 are as follows:

a. to specify the requirement for the System Operator and Users to provide unbiased forecasts of both Active Demand and Reactive Demand on the Transmission System within specified timescales. These forecasts are used by the System Operator for Operational Planning purposes, and in the Programming Phase, and the Control Phase;

b. to describe information to be provided by Users to the System Operator in the post Control Phase; and

c. to describe certain factors to be taken into account by the System Operator and Users when preparing forecasts of both Active Demand and Reactive Demand on the Transmission System.

Sub-section DSC 3.1 outlines the obligations on the System Operator, Generators and other Users regarding the preparation of forecasts of Active Demand, Reactive Demand and VRPP output for the Transmission System. DSC 3.3 sets out the timescales within which Users shall provide forecasts of both Active Demand (MW) and Reactive Demand (MVar) to the System Operator, and the timescales within which the System Operator shall provide forecasts to Generators and Users. These demand forecasts are required for certain operational purposes, specifically the Operational Planning Phase requires annual forecasts of both Active Demand and Reactive Demand on the Transmission System for the succeeding 2 years; the

Programming Phase requires weekly forecasts of both Active Demand and Reactive Demand on the Transmission System for the period 1 to 8 weeks ahead; and the Control Phase requires daily forecasts of Demand data on the Transmission System for the day ahead.

Phase	Applicable Parties	Forecast Data	Time period for which forecast data is required
Operational **Planning** **2 Years ahead** **(End of January each Year)**	All Distribution System Users with Demands in excess of 5MVA	Hourly forecast of Active and Reactive Demand	For Day of Users Max Demand, Day of System Peak and Day of System Minimum
	Users whose actions, in the opinion of System Operator, can have an effect on the stability of the System	Active and Reactive Demand	At specified times each week in the forecast period as identified by the System Operator in advance. The times shall be identified in 1hour periods for each week.
PROGRAMMING **PHASE** **1 - 8 Weeks** **(By 10:00am each Friday)**	All Users who forecast Demand changes in excess of 5MVA in any 1 hour period	Active and Reactive Demands	Any hour where the User forecasts a Demand change in excess of 5MVA for the period
Control Phase **0 - 24hrs** **Commencing 00:00**	all identified Users with Demand changes in excess of 5MVA in any 1 hour period	Active and Reactive Demands	Any hour where the Users forecasts a Demand change in excess of 5MVA for the period.

DSC 3.3 deals with the provision of Demand Control data in timescales consistent with the Operational Planning Phase, the Programming Phase, and the Control Phase.

DSC 3.3.3 Data required by the System Operator and Users of the System

Operational Planning Phase

No later than the end of October each year, the System Operator shall notify each User in writing of the forecast information listed below for each of the following 2 Operational Years:

a. the date and time of the forecast annual peak Active Demand and Reactive Demand on the Transmission System at annual maximum Demand conditions; and

b. the date and time of the forecast annual minimum Active Demand and Reactive Demand on the Transmission System at average minimum Demand conditions.

By the end of January of each year, each User shall provide to the System Operator in writing, the forecast information listed below for each of the succeeding 2 Operational Years:

Each Directly Connected Customer and Distribution Customers with demands in excess of 5 MVA shall provide forecast profiles of hourly Active Power Demand, at the Interconnection Point, for the day of that Users maximum Demand and for the day specified by the System Operator as the day of forecast annual peak Demand. These forecasts shall reflect annual maximum Demand conditions;

Each Directly Connected Customer shall provide forecasts of their annual Active Demand requirements, at the Interconnection Point, for Average Conditions;

Each Directly Connected Customer, at the Interconnection Point, shall provide forecasts of the profile of hourly Active Demand for the day specified by the System Operator as the day of forecast minimum Demand at Average Conditions.

User forecasts of both Active Demand and Reactive Demand on the Transmission System provided to the System Operator in accordance with Sub-section DSC 3.3 must reflect the User's best estimates of its forecast requirements.

The System Operator shall use the information supplied to it to prepare forecasts of both Active Demand and Reactive Demand on the Transmission System for use in the Operational Planning Phase.

DSC 3.3.4 Data required by the System Operator - Programming Phase

For the period of 1 to 8 weeks ahead each User directly connected to the Transmission System and identified Customers with changes in excess of 5 MVA shall supply to the System Operator in writing by 13:00 hours each Thursday hourly profiles of Demand for Active Power (MW) and Reactive Power (MVAR) at an Interconnection Point.

The System Operator shall use the information supplied to it in preparing its forecasts of Demand for Active Power and Reactive Power on the Transmission System for the purposes of the Programming Phase.

DSC 3.3.5 Control Phase

Each User shall notify the System Operator of any Demand Control which may result in a Demand change of 5 MVA or more averaged over any hour on any Interconnection Point which is planned after 10:00 hours, and of any changes to the planned Demand Control notified to the System Operator prior to 10:00 hours as soon as possible after the formulation of the new plans.

DSC 3.3.6 Post Control Phase

Each User shall supply MW profiles for the previous calendar day of the amount and duration of Demand reduction achieved from the use of Demand Control of 1 MW or more on an hourly basis;

DSC 3.3.7 VRPP Generation Short term Resource Forecasting

The Licensee requires the VRPP to provide quality resource forecasts from reputable and industry proven methods, and or in accordance with requirements that will be dictated by the Licensee in the transmission Interconnection Agreement or any other agreement between Licensee and the VRPP. The forecast should provide the following information:

Medium-Term Forecast: a rolling hourly resource forecast submitted to Licensee for the next 168 hours. The rolling hourly forecast means the forecast must be provided on an hourly basis.

Short-Term Forecast: Licensee reserves the right to also request a rolling 5-minute resource forecast to be submitted to Licensee and/or the centralized forecasting vendor for the next 6 hours.

The forecasts must be provided to Licensee through web service or ftp (File Transfer Protocol) site delivery in a format to be agreed upon with Licensee. Licensee reserves the right to request a specific file format that the VRPP must accommodate

DSC 3.3.8 Co-generation Short term Resource Forecasting

To the extent that a host process, in the case of Cogeneration Plants, is the driver of the export power to the grid, such an entity shall submit a two (2) week projection of their export expectation to the System Operator every Wednesday or within 24 hours of request, such that this information can be used to optimize the expected output of the despatchable Generating Units on the Grid.

DSC 3.3.9 Embedded Generator information

Information relating to Generating Plant Embedded in the Distribution System and not subject to Central Despatch shall be provided, where specified, to the System Operator. Users with their own generation may be required to furnish such information should the System Operator reasonably consider that it would affect its Demand forecasts.

Phase	Applicable Parties	Forecast Data	Time period for which forecast data is required
Control Phase **24hrs** **Commencing 00:00**	Embedded Generators with output changes in excess of 5MVA in any ‰ hour period	Active and Reactive Generation	Any ‰ hour where the Embedded Generator forecasts an output change in excess of 5MVA for the period.

DSC 3.4 System Operator and User Forecast

The following factors shall be taken into account by the System Operator and the Users when conducting Demand forecasting in the Operational Planning Phase:

a. Historic Demand Data;

b. Weather forecasts (NB Responsibility for weather correction of User's loads rests with the User);

c. Historic Demand trends;

d. Incidence of major events or activities;

e. Generating Unit active power generation forecasts or schedules;

f. Demand transfers;

g. Interconnection with adjacent Interconnection Points;

h. Planned Demand reduction (e.g. block load shedding); and

i. Any other factor reasonably considered necessary that may impact the Demand forecast.

The following factors shall be taken into account by the System Operator when carrying out Demand forecasting in the Programming and Control Phases:

a. Historic Demand data including Transmission System Losses;

b. Weather forecasts and the current and historic weather conditions;

c. The incidence of major events or activities which are known to System Operator in advance;

d. Demand Control of 1 MW or more; and

e. Other information supplied by Users.

The System Operator shall produce forecasts of Demand using a forecasting methodology taking into account the above factors to produce, by statistical means, unbiased forecasts of Demand including that to be met by Generating Plant.

DSC 3.5 Outage Planning and Data Provision

DSC 3.5.1 Introduction

The Despatch Code is concerned with the coordination through various timescales, of Planned Outages of Plant and Apparatus on the Transmission and Distribution Systems for construction, repair and maintenance, with the release of Generating Units for construction, repair and maintenance.

Sub-section DSC 3.5 establishes procedures to enable the collection of such outage data from Generators and Users as is required by the System Operator to comply with the requirements of the Generation, Despatch, Supply, Distribution and Transmission Codes.

The means of providing the information to the System Operator and its confirmation includes any non-transitory written form which enables the recipient to retain the information.

In general terms there is a preferred time period for planned outages of Generating Units, and parts of the Transmission and Distribution Systems. These preferred time periods are determined by reference to the excess of the total capacity of

Generating Plant available over the sum of Demand plus the Operating Margin at the relevant time.

In the Despatch Code, "Year 0" means the current calendar year at any time, Year 1 means the next calendar year at any time, Year 2 means the calendar year after Year 1, and so on.

DSC 3.5.2 Objective

The main objective of this section 3 of the Despatch Code is to ensure, as far as possible, that the System Operator co-ordinates, optimizes and approves Outages of Generating Units taking into account Transmission and Distribution System Outages in order to minimize the number and effect of constraints on the Transmission System and in order to ensure that, so far as possible, forecast Demand plus the Operating Margin is met.

To achieve he main objective, this section sets out the Operational Planning Procedure and typical timetable for the co-ordination of outage requirements for Plant and Apparatus to be provided by Users to enable the System Operator to operate the System.

It also specifies the information to be provided by Users to the System Operator to allow it to meet its obligations under the Codes.

The System Operator shall, in relation to all matters to be undertaken pursuant to this Despatch Code, including the co-ordination of Generator Outages, act reasonably and in good faith in the discharge of its obligations.

DSC 3.6 Information flow and coordination

DSC 3.6.1 Embedded Generating Plant

Information relating to Embedded Generating Plant not subject to Central Despatch whose Registered Capacity is greater than 5 MVA shall be provided where specified directly to the System Operator. This may include Users with own Generation where the System Operator considers it appropriate.

DSC 3.6.2 Other Plant and Apparatus

Information relating to all Plant and Apparatus connected to the System, or that which may affect its Operation, shall be provided to the System Operator on request.

DSC 3.7 Timescales and data

The following information is required to be provided by Users and Generators to the System Operator in the timescales indicated.

The Operational Planning Phase covers the Year 1 period. For all Generators and Users with Interconnection Points on the Distribution System where the System Operator has identified that such Customers must comply with the outage planning requirements of this code due to the impact that their outages may have on the System, such Generators and Users are to inform the System Operator of proposed planned outages required at the Interconnection Points for the following year commencing January 1st (Year 1).

The information gathered through this Despatch Code shall be used by the System Operator in the formation of the Transmission and Distribution System Outage Plan which shall be issued at the end of October.

As time passes the Year 1 plan becomes the Year 0 or current year plan. The Outage plan shall be kept up to date during year 0 by the System Operator, taking account of System conditions, planned Outage schedule deviations of Embedded Generators and User's Equipment connected to the Distribution System.

This Despatch Code does not provide requirements for the notification and forward planning of outages on the System other than for those identified in sub-section DSC 12.4.2.

The Programming Phase covers the period from one (1) week. The phase commences at 13:00 each Friday and at this time the System Operator shall issue the week ahead outage plan covering all outages on the System.

DSC 3.8 Planning of Generation Outages

The planning of Generator outages is subject to the provisions of the Generation Code. The three (3) year Generator outage planning cycle is summarized below in DSC 3.3.2, DSC 3.3.3 and DSC 3.3.4.

The System Operator shall develop overall generation maintenance plans for three (3) Years in advance. The plans which must incorporate statutory maintenance requirements shall be reviewed annually and updated as may be necessary.

Generators are required to submit to the System Operator on or before the first day of July of each Year a rolling three (3) Year plan for the scheduled maintenance requirement for their facility beginning in January of the following Year.

The System Operator shall obtain Scheduling information from Generators for Embedded Generating Plant not subject to Central Despatch where it considers it appropriate and relevant.

The Scheduling information shall specify the following on an individual Generating Unit basis:

a. the period the unit is required;

b. the planned half-hourly output; and

c. any other information the System Operator reasonably considers necessary

The System Operator shall endeavor to schedule Outages in a non-discriminatory manner as far as System security constraints allow. Both the System Operator and Generator shall make best efforts to ensure that interconnection and other related facilities are maintained within the periods stipulated for scheduled maintenance of the Generating Unit.

DSC 3.9 Planning of Transmission Outages Affecting Generators

The procedure set out below is to be followed in each calendar year.

The planning of Transmission System Outages is dependent on the schedule of Generator Outages.

The System Operator shall plan Transmission System Outages required in Years 2 and 3 as a result of construction or refurbishment works taking due account of known requirements. It is not anticipated that any detail of maintenance outages on the Transmission System will be available 2 or 3 years ahead.

The planning of Transmission System Outages required in Years 0 and 1 ahead shall, in addition, take into account Transmission System Outages required as a result of maintenance.

Transmission System Outages and Generating Unit Outages shall be coordinated so that, in general, Generating Unit Outages shall take precedence over Transmission System Outages but subject always, in any particular case, to the System Operator’s discretion to determine otherwise on the basis of reasons relating to the proper operation of the Transmission System.

By the end of October in each year the System Operator shall draw up a draft Transmission System Outage plan covering the period Years 2 and 3 for the System Operator internal use and shall notify each User in writing of those aspects of the draft plan which may operationally affect such User including, in particular, proposed start dates and end dates of relevant Transmission System Outages. A copy of the draft transmission outage plan shall be submitted to the OUR annually. The System Operator shall indicate to a Generator restrictions on the Scheduling and Despatch of Generating Units to allow the security of the Transmission System to be maintained in accordance with the Licence.

DSC 3.10 Medium Term Operational Planning - Planning for Year 1

The plan for Year 2 produced pursuant to DSC sub-section 3.4.5 above shall become the draft Transmission System Outage plan for Year 1 when, by the passage of time, Year 2 becomes Year 1. Each calendar year the System Operator shall update the draft Transmission System Outage plan for Year 1 and shall, in addition, take into account Outages required as a result of maintenance work.

By the end of September each year Users shall submit to the System Operator details of any maintenance outages required at the Interconnection Point for the following Year 1. Maintenance outages scheduled by the System Operator shall also be included in the transmission outage plan.

By the end of October each year the System Operator shall issue the final Transmission System Outage plan for Year 1. A copy this Transmission System Outage Plan shall be submitted to the OUR annually.

The System Operator shall notify each User in writing of those aspects of the plan which may operationally affect such User including, in particular, proposed start dates and end dates of relevant Transmission System Outages. The System Operator shall also indicate where a need exists to use emergency switching, emergency load management or other measures including restrictions on the Scheduling and Despatch of Generating Units to allow the security of the Transmission System to be maintained.

DSC 3.11 Short Term Operational Planning

The Transmission System Outage plan for Year 1 issued under DSC 3.5 shall become the final plan for Year 0 when by the passage of time Year 1 becomes Year 0. The System Operator shall keep the Transmission System Outage Plan updated during Year 0 to take account of fault outages and changes to outage durations of both Generator and Transmission System Equipment.

The System Operator shall develop a Distribution System Outage plan for Year 0. The System Operator shall keep the Distribution System Outage Plan updated during Year 0 to take account of fault outages and changes to outage plans and durations of both Embedded Generators and Distribution System Equipment.

DSC 3.12 Programming Phase

Each Friday the System Operator shall update the Transmission and Distribution System Outage plans for the following one week period beginning at 13:00 hours on the Friday.

The Transmission System Outage plan for the week ahead shall determine the Transmission Constraints which impact on the Unit Commitment Schedule which the System Operator prepares each working day in accordance with Clause 3.5.1 of the Despatch Code.

The System Operator shall notify each User in writing of those aspects of the plan which may operationally affect such User including in particular proposed start dates and end dates of relevant Transmission and Distribution System Outages. The System Operator shall also indicate where a need exists to use emergency switching, emergency load management or other measures including restrictions on the Despatch of Generating Units to allow the security of the Transmission and Distribution System to be maintained.

During the Programming Phase each User and the System Operator shall inform each other immediately if there is any requirement to depart from the Outages and actions determined and notified under this subsection.

The programming of outages shall also be subject to the following Licensee internal policy documents:

a. Engineering Instruction 1.11 - Planned Outage Procedure;

b. System Operation Policy and Procedure 14 - Planned Outage Procedure T & D; and

c. System Operation Policy and Procedure 19 - Planned Outage Procedure.

For reference purposes these Procedures are reproduced in Appendix A.

These Procedures outline notice requirements for the submission of outage requests to the System Operator. The provisions in this Despatch Code shall not supersede the requirement to submit an outage request within the timescales specified in the said Procedures.

The fact that a transmission outage appears in the Year 1 Transmission Outage Programme does not preclude the requirement to submit an outage request in accordance with the internal Procedures.

DSC 4 OPERATING MARGIN

DSC 4.1 Introduction

Section DSC 4 of Code sets out the types of reserves making up the Operating Margin that the System Operator may use in the Control Phase.

DSC 4.2 Operating Margin Constituents

The Operating Margin comprises Contingency Reserve plus Operating Reserve.

Contingency Reserve is the margin of Generation Capacity required in the period from 24 hours ahead down to real time, over and above the forecast Demand. It is provided by Generating Units that are not required to be synchronized but which must be held Available to Synchronize within a defined timescale.

Operating Reserve provides spare Generation Capacity for Frequency control in real time (Spinning Reserve) and quick time contingency (10_minutes Reserve) and is provided by Generating Units that are either synchronized or can be synchronized within minutes. Contingency Reserve and Operating Reserve provide against uncertainties in Availability of Generating Units and in Demand forecasts. Operating Reserve consists of Spinning Reserve and 10-minute Reserve.

DSC 4.3 Contingency Reserve

The System Operator shall determine the amount of Contingency Reserve required for each hour up to 24 hours ahead, taking due consideration of relevant factors, including but not limited to the following;

a. Availability and historical reliability performance of individual Generating Units;

b. Notified Risks of Trip of individual Generating Units; or

c. Demand forecasting uncertainties.

DSC 4.4 Operating Reserve

The System Operator shall determine the amount of Spinning Reserve and 10 Minute Reserve that must be available to it from Generating Units at any time to ensure System security. The System Operator Operating Reserve policy shall take due consideration of relevant factors, including but not limited to the following:

a. the magnitude of the largest Active Power infeed from Generating Units;

b. the predicted Frequency drop following loss of the largest infeed as may be determined through simulation using a dynamic model of the Total System;

c. the extent to which Demand Control can be implemented;

d. the cost of providing Operating Reserve at any point in time; and

e. ambient weather conditions, insofar as they may affect, directly or indirectly, Generating Unit and/or Transmission System reliability.

f. Variability of intermittent renewable generation.

The System Operator shall keep records of the Operating Reserve policy and of significant alterations to it as determined by the above and any other factors.

DSC 4.5 Procedures

The Procedures used by the System Operator to determine the Operating Margin are set out in the following documents:

a. The Generation Code including the Schedules; and

b. System Operation Policy and Procedure No 8 Operating Spinning Reserve.

DSC 5 MERIT ORDER SYSTEM

The System Operator shall establish a Merit Order based on the real or contracted Variable Operating Cost component of each Generating Unit or Complex, whichever is applicable.

The Variable Cost of each Generating Unit or Complex is the sum of the Variable Operating & Maintenance Cost (VOM) and the Fuel Cost. In mathematical form:

Merit Order Cost ($/MWh) = Fuel Cost ($/MBTU) x Full Load Heat Rate (MBTU/MWh) + VOM ($/MWh).

This information allows the System Operator to rank the Generating Units in the order of their Full Load Point cost of operation.

The commitment and de-commitment of units in the cost optimization process shall be guided by a number of system parameters including load, available units, the Merit Order Ranking and the forecasted duration. Once committed, the Despatch level of each Generating Unit or Complex shall be determined by the application of the equal incremental cost principles in Economic Despatch as described in sub-section DSC 3.5.

The Generating Units Committed and Scheduled in accordance with the Merit Order ranking shall be selected for Generation Despatch subjected but not limited to the following factors for each Generator or Complex:

a. real or contracted Fuel Price;

b. real or Contracted Variable Operations and Maintenance Price;

c. energy Price;

d. declared and projected (MW) capability;

e. declared and contracted operating characteristics including inter alia;

f. Heat Rate Characteristics (Real or contracted);

g. start-up cost of the units;

h. Transmission Penalty Factor;

i. Network Stability and Security;

j. Spinning and Other Operating Reserves;

k. Units that have been declared based on their contract, as Take-As-Available, are not influenced by the merit order and equal incremental cost optimization processes.

DSC 5.1 NOTIFICATION OF MERIT ORDER

The System Operator shall notify the Generator as to the relative position of its Despatch-able Generating Unit(s) in the Merit Order in terms of ranking number each Week.

The System Operator shall notify the OUR and the Minister of the daily revised Unit Commitment Schedule and the actual Despatch for the prior twenty four (24) hours.

DSC 5.2 Review of Merit Order and Despatch Input

DSC 5.2.1 Fuel Data

The Merit Order shall be revised on an ongoing basis to reflect the latest available information which includes changes in delivered fuel prices as they occur, consistent with the fuel procurement cycle for each Generating Facility and updates in VOM consistent with the Generator's reporting or business cycle. Updated Merit Order must be declared at the beginning of each Month. Where there is the need to adjust this Merit Order within this monthly cycle the updated Merit Order must be declared within 24 hours of being effected.

Generator shall provide the latest fuel cost and/or VOM information to the System Operator for its Generating Facilities within 24 hours of a request or from the time when such information becomes available.

DSC 5.2.2 Heat Rate Data

Heat Rate is computed by dividing the total British thermal unit (Btu) content of fuel consumed for electricity generation by the resulting net kilowatt-hour generation. The Basis of the value should always be expressed as either Lower Heating Value (LHV) or Higher Heating Value (HHV). The basis of the heating value provided shall be consistent with the relevant contractual arrangements and the capability of the generation technology employed.

The Heat Rate data for each Generating Unit is necessary to determine its variable fuel operating cost. All contracts for new thermal generating capacity shall have a guaranteed Heat Rate curve or point.

The Heat Rate Tests for each Generating Unit, not having a guaranteed curve or point, shall normally be conducted at least twice annually or as stipulated by contract. The schedules for the Heat Rate Test for all Despatchable Generating Units shall be developed by the System Operator at least one Month before the end of the preceding Year. The Heat Rate Test schedules may be adjusted within the Year to accommodate unforeseen circumstances, subject to agreement between the Generator and the System Operator. Such schedules for Heat Rate Test shall be submitted to the OUR by the System Operator.

The Heat Rate Test shall be conducted at a minimum of four (4) output levels from the minimum output level to the maximum output level for each Generating Unit.

The Heat Rate information obtained from Heat Rate Tests together with the guaranteed Heat Rates (for units to which this is applicable) shall be used as one of the inputs to the Generator Scheduling and Dispatch optimization process.

If the System Operator has sufficient reasons to believe that the Heat Rate of a Generating Unit which does not have a guaranteed curve or point, has changed significantly within the Month or since the last test (due to rehabilitation, damage etc.) the System Operator may request the Generator to conduct a Heat Rate Test in accordance with the Licensee Heat Rate Testing Policy (in the case of Licensee owned generators) or other approved policy (in the case of non-Licensee generators) and update the Heat Rate curve for such a Generating Unit. All costs associated with the Heat Rate test shall be the responsibility of the Generator.

The Generator may request a heat rate test of its own unit if it can provide information to substantiate that it has made improvements in the performance of its Unit(s). No more than two such requests will be accommodated within any calendar year.

Heat Rate Tests for all Generating Units, including those of the Single Buyer, shall be coordinated (mutually agreed date) by the System Control Engineer. The System Operator shall reserve the right to witness all such tests.

The OUR shall be advised and duly notified beforehand when such tests are contemplated and carried out and reserves the right to witness all such tests.

In the case of Independent Power Producers, the information on which the Generating Units will be ranked shall be based on the contractually agreed performance or such other criteria as established through the Power Purchase Agreement between the Generator and the System Operator.

DSC 6 UNIT COMMITMENT SCHEDULING AND DESPATCH

It is the System Operator's obligation to prepare a Unit Commitment and Despatch Schedule which reasonably reflects the likely System conditions. This schedule shall be prepared for the following Week and revised on a daily basis, except for weekend days and public holidays. The scheduling of Generating Units shall be in accordance with the latest available information, subject to relevant technical constraints specified in Sub-section 3.2.

Each Generator must submit to the System Control Centre by approved communication means a declaration of plant availability and capability, and any other information as agreed between the Generator and the System Operator from time to time. This data is to be declared to the System Operator in order to facilitate the timely preparation of a Unit Commitment Schedule.

A Weekly Unit Commitment Schedule and Despatch forecast shall not be regarded by any Generator to be Despatch Instructions but shall be provided as a service to Generators for planning purposes.

The daily revision of the Unit Commitment and Despatch Schedule shall at all times take precedence over the short-term predictions.

DSC 6.1 Preparation of Unit Commitment and Despatch Schedule

In the preparation of Unit Commitment and Despatch Schedule, the System Operator shall take into consideration, among other things pertinent to commitment schedule, the following factors:

a. Forecasted Demand and geographical Demand distribution;

b. Each Generator's declaration of each Generating Unit(s) MW capability and availability;

c. Generator's contracted operating characteristics;

d. Contracted and declared Heat Rate curve or point;

e. Fuel prices and constraints;

f. System reserve requirements;

g. System Stability implications, frequency and voltage control; and

h. System constraints.

Monday - Friday: The daily schedule of expected Availability and Generation Despatch shall be prepared by System Control Centre and made available to the System Control Engineer by 1 p.m. each day for the 24 hour period starting 1 p.m. to 1 p.m. the following day. This shall be reviewed by 1 p.m. on the following day.

Saturday-Sunday: The daily schedule of expected availability and generation levels for the weekend shall be done and made available to the System Control Engineer by 1 p.m. on the Friday preceding the weekend. This schedule shall cover the period from Friday 1 p.m. to Monday 1 p.m. and shall be reviewed by 1 p.m. on the Monday afternoon.

To facilitate preparation of these schedules, the Generator shall make a declaration of plant availability and capability over the scheduled period and any other information, as agreed between the Generator and the System Operator from time to time for remaining hours in the current day starting at 11 am.

The specific procedure for receiving data and making notification of commitment of Generating Units for Despatch shall be based on the following:

a. An agreed and approved means of communication between the Generator and System Control Engineer with adequate backup in case of the failure of this approved means; and

b. In order to ensure rapid transfer of information an interim declaration shall normally be verbally submitted in the first instance and shall be confirmed by the approved means without delay.

Where a Generator becomes aware of any changes in these declared values or other data subsequent to the declaration, then the Generator shall without delay notify the System Control Engineer.

DSC 6.2 Despatcher Training Simulator (DTS)

The System Operator shall maintain a functional Dispatcher Training Simulator as part of its SCADA system.

The System Operator shall request all the data required from each Generator as specified in section DSC 16 and as required under sub-section DSC 3.1, the Data Registration section of this Despatch Code

The Despatcher Training Simulator shall be used to evaluate the historical performance of the system, to validate historical actions taken and to train System operators in the management and control of the System.

The DTS should also be used to test the adequacy of the System Operator's System Restoration Procedures and to guide the development of any new Operating Policy and Procedure.

Generators shall provide information requested by the System Operator to facilitate its maintenance of an accurate and functional Dispatcher Training Simulator.

DSC 6.3 Despatch for Operations

This operations section of the Despatch Code is concerned with defining the operational responsibilities of the System Operator and Generators in respect of Despatch and the Despatch Processes active during real time operation of the System. This section of the Despatch Code covers the following areas:

a. SCADA System Real Time Update (demand and generator availability and capability);

b. Unit Commitment and Dispatch Real Time Update;

c. Non Despatchable (VRPP) monitoring and management;

d. Generator Outage Execution;

e. Generating Unit synchronization;

f. Frequency (AGC) and Voltage Control;

g. Reserve Margin Monitoring and Control ;

h. Despatch Deviation Tracking and Reporting;

i. After the Fact (AFE) Variance Analysis and Reporting;

j. Safety Co-ordination; and

k. Contingency Planning.

DSC 7 SCADA SYSTEM UPDATE

DSC 7.1 Real Time Demand Forecast

The System Operator shall update the daily projected Demand Forecast in real time with consideration for the change in demand influencing factors such as temperature, weather and change in customer expected use based on actual demand trend.

The System Control Engineer will keep the Unit Commitment and Despatch model in the SCADA system updated with the revised demand forecast.

DSC 7.2 Real Time Generator Availability and Capability Update

The System Operator shall update the Availability and Capability of each Generator in the SCADA system in real time based on information obtained from communicating with the Generators.

DSC 7.2.1 Changes to generation conditions

The Generator shall notify the System Operator as soon as possible of any factors which will or are likely to, affect the power output capability, flexibility, response or cost of production of any of its Generating Units.

Generating Units and apparatus shall not be taken out of service or rendered unavailable without reference to the System Operator except in cases of Emergency. In such cases the System Control Engineer shall be informed as soon as possible of the action taken.

A Generator experiencing an unplanned outage of any of its Generating Units shall inform the System Operator as soon as possible of all relevant details concerning this outage. As soon as the cause of the outage has been properly assessed and a recovery plan established, the Generator shall inform the System Operator of the expected time and the condition under which the Generating Unit shall return to service.

The actual time that the outage occurred and the Generating Unit was returned to service and any other information deemed to be important in relation to the outage shall be logged by the System Control Engineer.

DSC 7.3 Unit Commitment and Despatch Real Time Update

Generation and delivery or transfer of electricity into the Grid, to the extent allowed by Transmission System operating constraints and the dynamic operating characteristics of available Generating Units, among other things, based on equal incremental cost principles.

In order to efficiently operate and manage the System Grid in a safe, secure and economic manner, the System Operator will require accurate and timely information on the Generating Units' including, availability, efficiency and technical operating capability.

This section outlines the procedures used to determine how individual Generating Units or Facilities are operated in parallel to achieve these objectives based on the information received by the System Operator.

DSC 7.3.1 Unit Commitment

The System Operator shall update the planned unit commitment schedule based on new real time information obtained from Generators and a revised demand forecast.

The System operation shall issue timely instruction to Generators to start their Generating units and place them into service to meet the anticipated Demand.

Each Generator is required to ensure that their Generating Unit is prepared and available at their declared capability to respond to a dispatch instruction from the System Operator based on the required unit commitment schedule.

DSC 7.3.2 Despatch Instructions

This clause sets out the procedures for issuing Despatch Instructions to despatchable Generating Units and the responsibilities of the System Control Engineer and the Generating Unit Controllers in the minute to minute control time frame.

DSC 7.3.3 Real Power (MW) Dispatch

Real Power (MW) dispatch shall be based on an Equal Incremental Cost principle to minimize the variable operating cost, subject to the considerations specified in sub-sections 3.2, 3.4, 3.5.1 respectively. Despatch Instructions are normally given on a half hourly basis or anytime that is warranted by the operational requirements of the System.

The Equal Incremental Cost Principle states that, to achieve the most economic Despatch of power generation each Generating Unit on line, should operate at the same System wide point of Incremental Cost to serve a given load, unless the limit of capacity of a Generating Unit or other imposed constraints prevents it from reaching that cost. The Incremental Cost is the cost required to produce an additional MWh of energy above a base amount.

DSC 7.3.4 Reactive Power (MVAR) Despatch

Reactive Power (MVAR) is despatched at the discretion of System Control Engineer to maintain the System voltage within the tolerable limits. Under normal operating conditions Generating Units operate at 0.85 pf but could be required to operate at as low as 0.8 pf and can be requested to absorb reactive power, within the minimum functional specification of the units.

In instances when the System Operator makes the request for the Generator to absorb VARS, the Generator should not be penalized on their electricity bill during that period, to the extent that the absorption of reactive power has affected the approved rate ratcheting mechanism.

All Generators are required to provide the generator capability curve for the unit upon request by the System Operator. The System Operator shall at all times use the most economical choice available to manage the system voltage.

DSC 7.3.5 Ancillary Service

The System Operator subject to the approval of the OUR may contract with suitably qualified Generators for ancillary services (Voltage Support, Frequency Control, Reserve Support, etc.) to the extent that it does not violate the Power Purchase Agreements.

DSC 7.3.6 Non-centrally Despatched Plant

Non Despatchable Generating Units shall operate as agreed upon between the System Operator and the Generator.

The System Operator shall inform such Generators where there is a need for outage on the Generating Unit or of any incident which would affect the operations or safety of the Generating Unit.

During an Emergency, or where there is life and property at risk, the System Operator and/or the Generator reserves the right to disconnect and so isolate any Generating Unit without prior notification. However, both Parties must communicate immediately once the risk has been neutralized, to inform of the action taken and why it was necessary to take such action without prior notice.

The Generator shall communicate with the System Control Engineer on matters of switching and Synchronization during normal operations and in the event of System Emergency.

DSC 8 INSTRUCTION TO SYNCHRONIZE/DESYNCHRONIZE

The times at which a Generator shall be synchronized and desynchronized shall be directed by the System Control Engineer.

DSC 9 FREQUENCY AND VOLTAGE CONTROL

DSC 9.1 Frequency and Voltage Management

Adherence to the frequency and voltage standards shall be the responsibility of the System Control Engineer who shall issue to each Generator the required Despatch Instructions for both Real Power (MW) and Reactive Power (MVAR) output or absorption in the case of Reactive Power, in accordance with the declared operating limits of each Generating Unit as agreed upon between the System Operator and the Generators to ensure adherence to these operating standards.

Automatic Generation Control (AGC) can be used to perform frequency control by sending signals to generator to adjust output.

To the extent that the application of AGC is deemed economically feasible to the consumer and technically possible based on the specific generator capability and/or its expected operating regime, each new Generator shall ensure that the Generating Units are AGC enabled and can, without human intervention, accept and respond to a signal to adjust load.

Additionally, the SCADA/EMS system shall have the capability to facilitate the use of AGC. The range of control afforded by the implementation of AGC shall be the subject of the Generator's PPA.

DSC 9.1.1 System Control Centre Responsibility

The System Control Engineer shall be responsible for issuing any instruction necessary to:

a. Maintain the voltage on the Transmission System in accordance with the normal operational limits of +/- 5%;

b. Maintain, or enable others to maintain, the voltage of supply to consumers within the limits of +/- 5% of the Nominal Operating Voltages;

c. Supply the Reactive Power requirements of the System as economically as possible, and to organize the disposition of Reactive Power reserves for proper control of the System voltage in accordance with the requirement of i) and ii) above;

d. Maintain frequency within the limits of 50 Hz ± 0.2 Hz

e. Designate Generating Units to operate in Despatch or Spinning Reserve mode

DSC 9.2 Generator Responsibility

The Generating Unit Controller shall be responsible for:

a. ensuring that the Generating Unit's mode of operation is as designated by the System Control Engineer;

b. ensuring that Generating Units operate in active power frequency control mode followed only by frequency control mode when in emergency/abnormal conditions unless operation in this mode has been agreed as being impracticable between the Generator and the System Operator;

c. ensuring that Generating Unit(s) automatic voltage regulators are in service continuously. The System Control Engineer shall be informed whenever a Generating Unit is operating without its automatic voltage regulator or Reactive Power limiter; and

d. notifying immediately the System Control Engineer of any unusual voltage, frequency or power condition or any dynamic disturbances occurring upon any Generating Unit.

In the event of a sudden change in System voltage a Generating Unit Controller shall not take action to override automatic Reactive Power generation response, unless instructed otherwise by the System Control Engineer or unless immediate action is necessary to comply with stability limits or declared constraints of plant apparatus.

DSC 10 OPERATING RESERVE MONITORING AND MANAGEMENT

DSC 10.1 Spinning Reserve

The System Operator shall carry a minimum Spinning Reserve margin as set out in Schedule D of this Code. The determination of the Spinning Reserve margin shall be based on economics and System Security considerations.

The System Operator may from time to time adjust its Spinning Reserve policy subject to the approval of the OUR. Before such approval can be granted, the System Operator shall submit the revised Spinning Reserve policy to the OUR for review, analysis and determination.

DSC 10.2 Operating Reserve

The System Operator shall co-ordinate Scheduled Outages such that the Ten Minute Reserve margin and the Operating Reserve margin are maintained at or above the level set out in Schedule D. This shall allow the System to be able to accommodate one of the largest Generating Units being forced out of service and still maintain adequate available Capacity to meet System Demand.

The Ten Minute Reserve margin shall comprise units which are able to be synchronized and provide real power within 10 minutes.

In the case of System Emergency and unplanned outages, the Scheduled Outages of Generating Units shall be rescheduled if possible to maintain the defined reserve margin as per SCHEDULE D.

DSC 11 DESPATCH DEVIATION TRACKING AND REPORTING

The System Operator shall keep a record all Despatch instructions and the compliance of each Generator with the instructions received.

Each Generator shall keep a record all dispatch instructions received and their level of compliance.

Despatch Deviation shall be calculated by the System Operator for all Despatchable Generators. This information shall be used to calculate the Despatch deviation penalties for Generators which have a Despatch deviation penalty as part of their Power Purchase Agreement (PPA).

DSC 11.1 After the Fact Evaluation (Variance Analysis)

The System Operator shall perform simulations to determine the actual Despatch performance for each day.

The System Operator shall do a daily comparison of the Planned Unit Commitment and Despatch with the Actual Unit Commitment and Despatch Achieved.

The System Operator shall provide a Despatch Variance Report to the OUR and the Minister with responsibility for energy for each Day. This report should identify and quantify as best as possible the contributing factors to Despatch variance. The System Operator must provide adequate explanation of all variances from the planned Despatch. Explanatory factors shall include changes to Generator Capability, Availability and Efficiency, System Stability and Security, Frequency and Demand.

All non-compliance with the required Merit Order Despatch shall be communicated in writing by the OUR and the Minister with responsibility for energy to the System Operator within 3 months of any such determination of non-compliance.

The System Operator shall keep a record all Despatch instructions and the compliance of each Generator with the instructions received.

The OUR shall ensure that an independent audit of the Despatch process is conducted annually.

All Generators are required to keep a record of their Despatch performance and shall provide reports to the OUR upon request. Generators are also required to take all steps to facilitate and comply with the information requirements of the OUR commissioned annual Despatch audit.

DSC 12 SAFETY CO-ORDINATION

DSC 12.1 Objective

The objective of sub-section DSC 6.2 is to ensure that the safety procedures adopted on either side of an Interconnection Point work together in such a way as to ensure the safety of personnel, and/or Plant at any time that work and/or testing is carried out at or near the Interconnection Point.

DSC 12.2 Approved Safety Management Systems

The System Operator in conjunction with the connecting Generator shall establish a Safety Management System specifying the principles and procedures, and where appropriate, the documentation to be applied so as to ensure the health and safety of all who are liable to be working or performing tests on the Generation System, or on Plant and Apparatus connected to it.

DSC 12.0 requires that an approved Safety Management System is applied by the System Operator to meet statutory and other requirements.

A Safety Management System is to be adopted and shall be jointly agreed at sites or locations where an Operational Interface exists. This shall include provision for persons approved by the System Operator and Generators to operate the Safety Management Systems in use by field personnel where appropriate.

DSC 12.2.1 Documentation

A system of documentation shall be maintained by the System Operator and the User which records the safety precautions taken when work or tests are to be carried out on Plant and/or Apparatus across the Operational Interface; and isolation and/or earthing of the other System is needed. Where relevant, copies of the Safety Management Systems and related documentation shall be exchanged between the System Operator and Users for each Operational Interface.

DSC 12.2.2 Authorized personnel

Safety Management System shall include the provision for written authorization of personnel concerned with the control, operation, work or testing of Plant and Apparatus forming part of, or connected to, the Generation System.

Each individual Authorization shall indicate the class of operation and/or work permitted and the section of the System to which the authorization applies.

The authorization of personnel concerned with the control, operation, work or testing of Plant and Apparatus which is under the safety management of the System

Operators System Control shall only be undertaken by the approved officers of the System Operator.

DSC 12.2.3 Local Safety Procedures

Sub-section DSC 12.4 specifies the procedures to be used by the System Operator and Generators for the establishment, and maintenance of switching and clearance procedures to ensure that work on Apparatus on the System or a User's System can be carried out safely. It applies only when work and/or testing, other than the System Tests covered by DSC 11, is to be carried out and where the safety of personnel or plant requires the System Operator and a Generator or Generators to liaise.

Sub-section DSC 12.4 does not define the Safety Rules to be adopted by the System Operator or any Generator but sets out the requirement to prepare procedures, which shall govern the interface between them. In particular it lays down the rules for agreeing the safety procedures (the Local Safety Procedures) which shall be adopted on either side of an Interconnection Point between the System Operator and any Generator.

Where the provisions of subsection DSC 6.4 require a party to approve the Local Safety Procedures of another Party, such approval does not imply that the approving party takes any responsibility for the adequacy of the Local Safety Procedures. The approval in such case only implies that there is nothing in the Local Safety Procedures that negates or frustrates any provision of the Local Safety Procedures of the approving Party for the relevant Interconnection Point.

Prior to the energizing of a new Interconnection Point (or, for an Interconnection Point which has been energised before the procedure set out in DSC 6.3 has been adopted, as soon as reasonably practicable), the System Operator and the relevant Generator shall each supply the other with a copy of the Local Safety Procedures which it intends to adopt on its side of the Interconnection Point.

The party from whom approval is sought shall, within 7 days of receipt of the Local Safety Procedures, send written comments to the issuing party giving:

a. its approval of the Local Safety Procedure; or

b. its reasons for refusing to give approval and the changes which it would wish to see to enable it to grant approval.

If the party from whom approval is sought requires more stringent Isolation and/or Earthing provisions then, to the extent that these provisions are not unreasonable, the other Party shall make such changes to its Local Safety Procedures as soon as is reasonably practicable.

If, subsequent to the approval of any Local Safety Procedures, the issuing party wishes to change any provision of the procedure, it shall prepare a version of the procedure showing the original text and clearly indicating the changes required to this text and shall seek approval of this procedure as if this procedure had not previously been approved.

If an approved Local Safety Procedures has been found to be unsound, revisions to this procedure, only to the extent that these are required to ensure the safety of personnel or Plant, may be implemented immediately, subject, only to the Safety coordinators of the other party or Parties having been informed of these changes and having confirmed that the changes do not increase the risk to their own personnel and/or plant and are understood.

DSC 12.2.4 Safety Coordinators

Prior to the energizing of a new Interconnection Point (or, for an Interconnection Point which has been energized before the procedure set out in DSC 6.4 has been adopted, as soon as reasonably practicable), the System Operator and the relevant Generator shall, in respect of this Interconnection Point, each appoint a person to act as Safety Coordinator and a second person to act as Safety Coordinator at any time that the first named person is unavailable.

The System Operator and the relevant User shall each inform the other, in writing and without delay, of the identity of the persons appointed by them as Safety Coordinators. In the event of an intention to replace the person appointed as Safety coordinator the other party to the Interconnection Point shall be notified of the identity of the new Safety coordinator without delay.

The Safety Coordinators shall be responsible for co-ordination of all matters concerning safety across the Interconnection Point, including but not limited to, the approval of Local Safety Procedures. A Safety coordinator may be responsible for more than one Interconnection Point site.

DSC 12.2.5 Isolation and Earthing

Without prejudice to the need to prepare and agree Local Safety Procedures for use at each Interconnection Point site, it would be expected that Isolation and earthing principles no less stringent than those outlined in Sub-sections DSC 6.5.2 and DSC 6.5.3 shall be adopted.

DSC 12.2.6 Isolation Device

Where Isolation is achieved by means of an Isolation Device, the isolating position shall be maintained in such a way as to minimize

the risk of inadvertent, accidental or unauthorized operation and that when put in this position, a notice or "tag" to this effect shall be attached.

Clearance to work on any Apparatus which requires this Isolation to be achieved shall only be issued when the procedure above has been completed.

DSC 12.2.7 Earthing Device

Where Earthing is achieved by means of an Earthing Device, the Earthing position shall be maintained in such a way as to minimise the risk of inadvertent, accidental or unauthorized operation and that when put in this position, a notice or "tag" to this effect shall be attached.

Clearance to work on any Apparatus that requires this Earthing to be achieved shall only be issued when the procedure above has been completed.

DSC 12.2.8 Site specific safety

Arrangements shall be made by all Parties to ensure site safety and security as required by statutory requirements. Arrangements shall also be made by all Parties to ensure that personnel are warned, by an appropriate means, of hazards specific to any site before entering any area of the site. This shall include hazards that may be temporary or permanent. Where these risks include contamination or similar, suitable decontamination facilities and procedures shall be provided.

Arrangements shall be made to facilitate inspections by the System Operator management and safety representatives to sites accommodating the System Operator owned Plant and Apparatus.

DSC 13 CONTINGENCY PLANNING

DSC 13.1 Introduction

This section of the Code covers the detailed System recovery procedures following a Major System Failure and the procedures where the System Operator intends to implement Black Start procedures.

DSC 13.2 Objectives

Section DSC 17 outlines Despatch requirements with a view to assisting the restart of the Total System or to operating the Total System in abnormal situations which require co-ordination between all Users with a common approach to give uniformity of priorities.

DSC 13.3 System recovery

The System Operator is responsible for the control of the Transmission System and the Distribution System.

Following a Major System Failure, the restoration of the System shall be managed through the implementation of a System Restoration Strategy developed by the System Operator under the requirements of section DSC 7 of the Transmission Code.

During the event of a Major System Failure, the following general procedures shall apply to restore power System-wide:

a. designate Generating Units with Black Start Capabilities to commence restoration;

b. restart these designated Generating Units;

c. establish a transmission line pathway to the nearest other Generating Unit which is to be restarted while clearing all Load in this pathway;

d. establish a manageable distribution load preferably adjacent to the Generating Unit;

e. start and synchronize the Generating Unit;

f. repeat procedures (d) to (e) above until all Generating Units required to restore power are brought back into service; and

g. gradually return Load to the System while ramping up the power output of the Generating Units until the System is totally restored.

h. Procedures (d) to (g) shall be used to restore the System after a partial System shutdown. For detailed information on System restoration procedures refer to the System Operator's System Restoration Policy and Procedures.

All Generators shall comply with instructions issued by the System Operator pursuant to the implementation of the System Restoration Strategy.

It should be recognized by Generators that the restoration of the System needs to be flexible and Generators shall comply with instruction issued by the System Operator during an event even if they conflict with the System Restoration Strategy.

DSC 13.4 User responsibilities

Each Generator shall follow the System Operator s instructions during a System restoration process, subject to safety of personnel, the System Operator;s and the Generator's Plant and Apparatus.

It shall be the responsibility of the Generator to ensure that any of its personnel who may reasonably be expected to be involved in System restoration procedures are familiar with, and are adequately trained and experienced in their standing instructions and other obligations so as to be able to implement the procedures notified by the System Operator.

DSC 13.5 Black Start Procedure

The procedure for a Black Start situation shall be that specified by the System Operator at the time of the Black Start situation. Generators shall abide by the System Operator instructions during a Black Start provided that the instructions are to operate within the operating parameters of each Generator.

The System Operator may issue instructions to a Generator with Black Start capability relating to the commencement of a Generator when an external power Supply is made available to it.

The System Operator shall also issue instructions relating to the restoration of Demand.

Black Start instructions shall be implemented in accordance with the following procedures:

a. a Generator with Black Start capability shall start-up as soon as possible and within two hours of an instruction from the System Operator to initiate start-up. The Generator shall confirm to the System Operator when start-up has been completed;

b. following such confirmation, the System Operator shall endeavor to stabilize that Generator by instructing the restoration of appropriate demand following which the System Operator may instruct the start-up and synchronization of the remaining available Generators at that Generating Facility and their loading with appropriate Demand to create a Power Island;

c. if during this Demand restoration process any Generator cannot keep within its safe operating parameters because of Demand conditions, the operator of the Generator shall inform the System Operator and the System Operator shall, where possible, either instruct Demand to be altered or shall re-configure the Transmission System or shall instruct a User to reconfigure its System in order to alleviate the problem being experienced by the Generator;

d. The System Operator accepts that the decision to keep a Generating Unit operating outside its safe operating parameters is one for the Operator of the Generator concerned. The System Operator shall accept and respond accordingly to a decision of the operator of a Generator to change Generation output on a Generator if it believes it is necessary to do so for safety reasons; and

The System Operator shall have procedures in place for emergency restoration of the System following events such as hurricanes, earthquakes and torrential rains.

These Procedures shall be reviewed and updated by the System Operator and may be incorporated into other procedures developed in accordance with section DSC 13.

The System Operator shall inform Generators of the end of a Black Start situation and the time at which the Transmission System resumed normal operation.

All notifications must be made promptly. Notifications by the System Operator to Users and responses may be made by telephone but must be confirmed within 30 minutes in writing. Where information is requested in writing throughout this Code, facsimile transmission or other electronic means as agreed with the System Operator in writing may be used.

DSC 13.6 Re-Synchronization Procedures

Where there is no Total System Shutdown but parts of the Transmission System are out of synchronism with each other, the System Operator shall instruct Users to regulate generation output or Demand to enable the separate parts to be re-synchronized. The System Operator shall inform the relevant Users when re-synchronization has taken place.

The System Operator shall issue whatever revised Despatch instructions are required to enable re-Synchronization and to return the Transmission System to normal operation.

DSC 13.7 Major System Failure Procedures

Major System Failures are unpredictable both with respect to timing and the resulting implications. The System Operator shall establish procedures for determining when an incident on the System shall be considered a Major System Failure and also establish outline procedures for handling these Major System Failures as required under the Electricity Act 2015, Part VII.

In certain circumstances, the System Operator may require an Emergency Operation Centre to be established to coordinate the response to a Major System Failure and to avoid placing further stress on existing System Operator and User operational control arrangements.

The System Operator shall inform Generators promptly that an Emergency Operation Centre is to be established and request all relevant Generators to implement System Incident Communications Procedures. The System Operator shall specify the responsibilities and functions of the Emergency Operations Centre and the relationship with existing operational and control arrangements.

The Emergency Operation Centre established in accordance with the System Operator's instructions shall have any responsibility for the Operation of the Transmission System and shall be the focal point for communication and the dissemination of information between the System Operator and senior management representatives of relevant Users, the OUR and Government.

During a Major System Failure, normal communication channels for operational control communication between the System Operator and Users shall continue to be used.

The System Operator shall decide when conditions no longer justify the need to use the Emergency Operation Centre and shall inform all relevant Generators within 30 minutes by facsimile or other agreed electronic means accordingly.

DSC 13.8 Major System Failure Communications

The System Operator and Generators shall ensure that there are suitable communication channels available and established protocols, including the responsibilities of senior members of staff, to facilitate the co-ordination of activities after a Major System Failure.

The System Operator and all Users shall maintain lists of telephone contact numbers at which, or through which, senior management representatives nominated for this purpose and who are fully authorized to make binding decisions on behalf of the System Operator or the relevant User can be contacted day or night.

The lists of telephone contact numbers shall be provided in writing prior to the time that a Generator connects to the Transmission System and must be up-dated and circulated to all relevant parties, in writing, whenever the information changes. Notifications and responses shall be made normally by telephone but must be confirmed in writing within 30 minutes.

All Major System Failure communications between the Senior Management representatives of the relevant Parties with regard to the System Operator's role in the Major System Failure shall be made via the Emergency Operation Centre if such a Centre has been established.

DSC 13.8.1 System Alerts/Warnings

In the event of Major System Failures, such as Total System Shutdown or a System separation, the System Operator shall issue promptly an alert warning to all Users.

The form of the Alert Warning will be:

a. This is an Alert timed at hours;

b. There is a (Major System Failure) at …... (place);

c. A System Normalization Procedure is being implemented;

d. Standby for further instructions.

DSC 14 INCIDENT INFORMATION SUPPLY

DSC 14.1 Introduction

This Despatch Code requires the System Operator and Generators to issue notices of all Incidents on their respective Systems that have or may have implications for the Transmission System or a User's System.

The System Operator shall determine that if Incident should be classified as a Major System Failure in accordance with Part VII of the Electricity Act 2015. DSC 14 sets out the procedures for reporting and subsequent assessment of Major System Failures.

Where a Significant Incident has been declared the System Operator may request an investigation be carried out.

The composition of such an investigation panel shall be appropriate to the Incident to be investigated.

Where there has been a series of Significant Incidents (that is to say, where a Significant Incident has caused or exacerbated another Significant Incident) the System Operator may determine that the investigation should include some or all of those Significant Incidents.

Any investigation under DSC 14 is separate from any inquiry which may be carried out under legal or statutory requirements.

Section DSC 14 requires the System Operator or a Generator to prepare:

a. a preliminary written Incident report within 24 hours of the Incident;

For a Major System Failure, a written report is required within 20 days of the Incident.

In addition, DSC 14 contains requirements governing the content of Major System Failure reports, the circulation of these reports, and their subsequent assessment and review by the Code Review Panel.

DSC 14.2 Objective

The objectives of section DSC 14 are:

a. to specify the obligations of the System Operator and Generators regarding the issue of notices of Incidents on their respective Systems;

b. to ensure notices of Incidents provide sufficient detail to allow recipients of such notices to fully assess the likely implications and risks and take the necessary actions required to maintain the security and stability of the Transmission System or a Generator's System;

c. to specify the arrangements for reporting Incidents that the System Operator has determined to be a Major System Failure; and

d. To provide for the review of all Major System Failure reports by the Code Review Panel to assess the effectiveness of policies adopted in accordance with this Despatch Code and the other Grid Codes.

DSC 14.3 Notification of Incidents

The System Operator and Generators shall issue notifications of Incidents on their respective Systems that have had or may have implications for the Transmission or Distribution System in the case of the Generator, or a Generator's system in the case of both the System Operator and Generator notifications. Where information is requested in writing throughout this Code, facsimile transmission or other electronic means as agreed with System Operator in writing may be used.

Without limiting the requirements of this Code, Incident notifications shall be issued for the following, subject to Sub-section DSC 14.3.1; where Plant has been Operated in excess of its rated capability and presented a hazard to Persons;

The activation of any alarm or indication of any abnormal operating condition; adverse weather conditions being experienced; breakdown of, faults on or temporary changes in the capabilities of Plant; breakdown of or faults on control, communication and Metering equipment; and increased risk of inadvertent operation of protection devices, relays or Equipment.

DSC 14.3.1 Incidents on the Transmission System

In the case of an Incident on the Transmission System, which has had or may have an Operational Effect on a Generator's System, the System Operator shall notify the Generator who's Generation System will be, is, or has been affected.

DSC 14.3.2 Incidents on a Generator's System

In the case of an Incident on a Generator's System, which has had or may have an operational effect on the Transmission System, the Generator shall notify the System Operator. Following notification by the Generator, the System Operator shall notify any other Users who's Systems will be, or have been affected.

DSC 14.4 Form of Notification

Incident notifications must be issued promptly. Notifications and responses to notifications may be made by telephone or the mass media, but shall be confirmed in writing within one (1) hour or as soon as it is practical to do so.

The appropriate party shall issue a notification (and any response to questions asked) of any Incident that has arisen independently of any other Incident.

The notification shall;

a. describe the Incident (but is not required to state its cause);

b. be of sufficient detail to enable the recipient of the notification to reasonably consider and assess the implications, and risks arising; and include the name of the individual reporting the Incident on behalf of the Grid Operator or the User.

The recipient of a notification may ask questions to clarify the notification and the provider of the notification shall, insofar as they are able, answer any questions raised.

An Incident notification shall be given as soon after the Incident as possible to allow the recipient to consider and assess the implications and risks arising from the Incident.

DSC 14.5 Major System Failure Reporting

The System Operator may determine that an Incident reported by it or a Generator shall be classified as a Major System Failure if it meets the criteria established in section 45(16) of the Electricity Act.

The System Operator shall promptly notify all potentially affected Users by telephone or other media that such a determination has been made and that procedures governing Major System Failure reporting are to be followed.

The System Operator shall confirm such notice within 30 minutes by facsimile or other electronic means. All affected Users shall acknowledge receipt of the notification within 15 minutes of receipt by facsimile or other electronic means.

DSC 14.5.1 Timing of Major System Failure reporting

Preliminary report

The System Operator or User must produce a preliminary written Incident Report within 24 hours.

DSC 14.5.2 Full Report

The System Operator or User must produce a full written Major System Failure report within 30 days of a Major System Failure

A Generator shall produce a Major System Failure Report within 20 days of a Major System Failure caused by its Generation System. This is to facilitate the System Operator preparing its Major System Failure Report within 30 days for submission to the Office and the Minister as required under the Electricity Act 2015.

DSC 14.5.3 Written reporting of Major System Failures by the SO to Generators.

In the case of a Major System Failure reported by the System Operator to a Generator, the System Operator shall provide a full written Major System Failure report to the OUR.

Upon the request of the System Operator, a Generator shall provide a report of the Incident to the System Operator. The System Operator may use the information contained from an Incident report from a Generator therein in preparing the written report.

DSC 14.5.4 Written Reporting of Major System Failures by Generators to the SO

In the case of an Incident, that has been reported by a Generator to the System Operator and determined by the System Operator as a major System Failure, the Generator shall provide a full written Major System Failure report to the System Operator. The System Operator shall not pass this report to other affected Users but may use the information contained therein in preparing a Major System Failure report to the OUR.

DSC 14.6 Form of Significant Incident Report

A full Major System Failure report prepared by the System Operator shall be sent to the Minister and the OUR. The full Major System Failure report shall contain confirmation of the Major System Failure notification together with full details relating to the Major System Failure.

DSC 14.6.1 Form

The Major System Failure report should, as a minimum, contain the following:

a. date and time of Significant Incident;

b. location;

c. Apparatus involved;

d. brief description of the Major System Failure

e. causes of the Failure

f. details of any Demand Control undertaken.

g. effect on other System Users including where appropriate:- duration of Incident; and estimated date and time of return to normal service.

h. effect on generation including, where appropriate:-

i. generation interrupted; frequency response achieved; MVAr performance achieved; and estimated date and time of return to normal service

j. measures and procedures taken to restore the system

k. measures that should be taken to avoid a recurrence of the failure

l. an assessment of the cost associated with the failure.

The above list is not intended to be exhaustive to this section DSC 14.

DSC 15 METERING AND DATA ACQUISITION

Refer to contents of the Licensee System Operator’s SCADA Policy.

DSC 16 DATA EXCHANGED BETWEEN THE SO AND GENERATORS

DSC 16.1 Schedule of Data

The following Table provides details of Schedules covering the data to be exchanged between the System Operator and Generators.

Abbreviations used in all Schedules	
TC	Transmission Planning Code
DC	Distribution Code
DSC	Dispatch Code
GC	Generation Interconnections Code
EI	Licensee Engineering Instructions
SOPP	Licensee System Operation Policies and Procedures

Schedule	Data Type	Description	User	Code section	Licensee Procedure
IV	Interconnection Point	Information related to Demand, demand transfer capability and a summary of Embedded Generators and Customer generation connected to the Interconnection Point.	Licensee	TC 3.3 TC 3.17	
V	Demand Control	Information related to Demand Control	Licensee	DSC 3.3 DSC 3.3 DSC 3.3	EI 1.6 SOPP 11

				GC 8	
VII	User Outages	Information required by the System Operator for outages on Users Systems, including outages affecting the auxiliary supplies of Generating Plants.	Licensee	DSC 3.1 DSC 3.12 DSC 3.12	EI 1.11 SOPP 14 SOPP 19
VIII	Generator Planning Parameters	Generator fixed Electrical Parameters		TC 7.5	
IX	Generator Operational Planning	Information required for Operational Planning purposes.		GC 8	SOPP 7
X	Scheduling and Dispatch	Operating Parameters required for Scheduling and Dispatch		GC 8 DSC 3	SOPP 7
XI	Generator Outages	Generator Outage Information.	GEN	DSC 3.2 GC 8. DSC 3	EI 1.11 SOPP 19
XII	System Operator information to Users	All relevant information		TC 5.3 DSC 3.3 DSC 3.3. DSC 12.5 TC 7.4.11 GC 8	

				GC 8	
XIII	Metering Data	All relevant information		TBA	EI 4.7

SCHEDULE I – USERS SYSTEM DATA

The data in this Schedule I is required from all Users interconnected directly to the Transmission System.

Data Description	Units	Code section	Licensee Instruction/ Procedure
Safety Coordinators	Text	DSC 33.4	
Reactive Compensation Equipment	Text	TC 5.3	SOPP 4
For all reactive compensation equipment connected to the User System at [12kV] and above, other than Power Factor correction equipment associated directly with a Customer Plant, the following details	MVar Text and/or Diagrams		SOPP 7
Type of equipment (e.g. fixed or variable(	Text		
Capacitive rating			
Inductive rating			
Operating range			
Details of any automatic control logic to enable operating characteristics to be determined **Point of Interconnection to the User System in terms of electrical location and System voltage**			

SCHEDULE II – LOAD CHARACTERISTICS DATA

The following information is required from each User regarding existing and future Interconnections for each Interconnection Point.

Data Description	Units	Data		Data Category
		YR 1	YR 2	
1. Details of individual loads which have fluctuating, pulsing or other characteristic significantly different from the typical range of Domestic, Commercial or Industrial loads Supplied.				TC 3.3 TC 3.17
Voltage sensitivity	MW/kV			
	MVAr/kV			
Frequency sensitivity	MW/Hz			
	MVAr/Hz			
3. Phase unbalance imposed on the Transmission System				
Maximum	%			
Average	%			
4. Maximum harmonic content imposed on the Transmission System	%			
5. Details of loads which may cause Demand fluctuations greater than [1 MW] at an Interconnection Point				

SCHEDULE III – DEMAND PROFILES AND ACTIVE ENERGY DATA

The following information is required from each User who is directly connected to the Transmission System with Demand.

1. Daily of User maximum Demand (MW) at Annual MD conditions

2. Day Peak.

Data Description	FY0	FY1	Update Time	Data Category
Forecast daily Demand profiles in respect of each User System (summated overall Interconnection Points for the Distribution System Operator and at the Interconnection Point for Embedded Generator	1. Day of User maximum Demand (MW) at Annual MD Conditions			TC 3.3
	2. Day of peak Transmission System Demand (MD) at Annual Conditions		End January	TC 3.17
	3. Transmission System Demand (MW) at Average Conditions (Delete as appropriate)			TC 5.3
				DSC 3.3
				GC 8
0000 : 0100				
0100 : 0200				
0200 : 0300				
0300 : 0400				
0400 : 0500				
0500 : 0600				
0600 : 0700				
0700 : 0800				

0800 : 0900

1000 : 1100

1100 : 1200

1200 : 1300

1300 : 1400

1400 : 1500

1500 : 1600

1600 : 1700

1700 : 1800

1800 : 1900

1900 : 2000

2000 : 2100

2100 : 2200

2200 : 2300

2300 : 2400

	Data Description	YR 0	YR 1	YR 2	Update Time	Data Category
	The annual MWh requirements for each User System for Non Embedded Generator at Average Conditions:				End Sept	TC 3.3 TC 3.17
						TC 5.3
1	Domestic					
2	Agricultural					
3	Commercial					
4	Industrial					

5	Parish		
6	Public Lighting		
7	[Any other identifiable categories of Generator]		
8	User System Losses		
	Applicable only to Non-Embedded Generator	End Sept	TC 3.3 TC 5.3
1	Total Demand (MW) on its System		
2	Active Energy (MWh) requirement on its System		
3	Active Energy from Embedded Generation		

SCHEDULE IV – INTERCONNECTION POINT DATA

The following information is required from each User who is directly connected to the Transmission System with Demand.

Data Description	Units	Data		Update Time	Data Category
		YR 1	YR 2		
1. Annual peak hour User Demand at Annual MD **Conditions**	MW Pf			End Sept	TC 3.3 TC 3.17
2. User Demand at Transmission System peak hour Demand at Annual MD **Conditions**	MW Pf			End Sept	TC 3.3 TC 3.17
3. User Demand at minimum hour Transmission System Demand at Average **Conditions**	MW Pf			End Sept	TC 3.3 TC 3.17
Where a User Demand or group of Demands may be fed by alternative Interconnection Point(s) , the following details should be provided:				End Sept	TC 3.3 TC 3.17
1. Interconnection Point(s)	Name of the alternative				
2. Demand transferred **3. Transfer arrangement**	MW MVAr				
4. Time to effect transfer	Hrs.				

SCHEDULE V – DEMAND CONTROL DATA

The following information is required from a Non-Embedded Customer.

Data Description	Units	Time Covered	Update Time	Data Category
Programming Phase: applicable to the Non-Embedded Generator				
Demand Control which may result in a Demand change of [1] MW or more on an hourly and Interconnection Point basis **1. Demand profile**	MW	Weeks 1 TO 8	10:00 Friday	DSC 3.3 El 1.6 SOPP 11
2. Duration of proposed Demand Control	Hrs.	Weeks 1 to 8	10:00 Friday	GC 8.
Control Phase: applicable to a Non-Embedded Generator				
1. Demand Control which may result in a **Demand change of 1 MW or more averaged over any hour on any Interconnection Supply Point which is planned after 10:00 hours**	Mw	Now to 7 Days	Immediate	DSC 3.3
2. Any changes to planned Demand Control notified to the System Operator prior to 10:00 Hours	Hrs.	Now to 7 Days	Immediate	
Post Control Phase				
Demand reduction achieved on previous calendar day of 1 MW or more averaged over any Interconnection Point, on an hourly and Interconnection Point basis **1. Active Power profiles**	MW	Previous Day	10:00 Daily	DSC 3.3
2. Duration	Hrs.	Previous Day	10:00 Daily	

SCHEDULE VII – USER OUTAGES DATA

Data Description	Timescale Covered	Update Time	Data Category
Generators and Non-Embedded Generator provide Details of Apparatus owned by them other than Generating Units at each Interconnection Point	Year 1	End Sept	
System Operator informs Users of aspects that may affect their Systems	Year 1		
Users inform System Operator if not in agreement with aspects as notified	Year 1		
System Operator issues final Transmission System outage plan with advice on Operational Effects on the Distribution and User Systems	Year 1	End Oct	DSC 3.12
Generators, and Non-Embedded Generator to inform System Operator of changes to outages previously requested	Week 8 ahead to year end	As occurring	DSC 3.12

SCHEDULE VIII – GENERATOR PLANNING PARAMETERS DATA

Generating Facility Name: ________________________________

The following details are required from each Generating Facility directly connected, or to be directly connected, to the Transmission System and/or an existing, or proposed, Embedded Generating Facility. The data shall be supplied for the following 3 years

Data Description	Units	Update Time	Data Category
Generating Facility Demand			
Demand associated with the Generating Facility supplied through the Transmission System or via a Generator's own system in addition to Demand supplied through unit transformer		End Sept	
1. Maximum Demand that could occur	MW MVAr		
2. Demand at the time of peak Transmission System Demand	MW MVAr		
3. Demand at the time of minimum Transmission System Demand	MW MVAr		

The data in the following table shall be supplied for each generating unit.

Data Description	Units	Update Time	Data Category
Individual Generating Unit Demand			
Demand supplied through unit transformer when Generating Unit is at Rated MW output	MW MVAr		
Generating Unit Performance and Parameters			
General			
1. Details of point of Interconnection to the Transmission System of the Generating Unit in	Text	As required	TC 7.5

terms of geographical and electrical location and system voltage, including a Single Line Diagram		
2. Type of Generating Unit (e.g. Steam Turbine Unit, Gas Turbine Unit, Cogeneration Unit, wind, etc.)	Text	
3. Registered Capacity	MW	
4. Distribution System Constrained Capacity (for Embedded Generating Units only)	MW	
5. Rated Active Power	MW	TC 7.5
6. Minimum Generation	MW	
7. Rated Apparent Power	MVA	
8. Rated terminal voltage	kV	
9. Generator Performance Chart at stator terminals	Chart	
10. Net Dependable Power Capacity (on a monthly basis)	MW	
12. Turbo-generator inertia constant (alternator plus prime	MW/MVA	
1. Direct axis synchronous reactance	% on MVA	
2. Direct axis transient reactance	% on MVA	
3. Direct axis sub-transient reactance	% on MVA	
4. Quadrature axis synchronous reactance	% on MVA	
5. Quadrature axis sub-transient reactance	% on MVA	
6. Stator leakage reactance	% on MVA	
7. Armature winding direct-current resistance	% on MVA	
Time Constants **1. Direct axis short-circuit transient time constant**	secs	TC 7.5

2. Direct axis short-circuit sub-transient time constant **3. Quadrature axis short-circuit sub-transient time constant** **4. Stator time constant**	

	Data Description	Units	Update Time	Data Category
	Governor Parameters (All Generating Units)			TC 7.5
	Governor system block diagram showing transfer function of individual elements		Diagram	
	Prime Mover Parameters			
	Generator Flexibility Performance			TC 7.5
	Details required with respect to Generators			
1	Rate of loading following a weekend shut-down (Generator and Generating Facility)		MW/Min	
2	Rate of loading following an overnight shut-down (Generator and Generating Facility)		MW/Min	
3	Block load following Synchronizing		MW	
4	Rate of De-loading from Rated MW		MW/Min	
5	Regulating range		MW	
6	Load rejection capability while still Synchronized and able to supply Load		MW	

SCHEDULE IX – GENERATOR OPERATIONAL PLANNING DATA

Generator Facility Name: ____

The following details are required from each Generator in respect of each Generating Unit

Data Description	Units	Data Category	Generating Unit and Generating Facility Data						
			U1	U2	U3	U4	U5	U6	GF
Steam Turbine Generating Units		GC 8							
1. Minimum notice required to synchronize under following conditions:									
o Hot start	Min								
o Warm start	Min								
o Cold start	Min								
2. Minimum time between synchronizing **different Generating Units at a Generating Facility**	Min								
3. Minimum block Load requirement on **synchronizing**	MW								
4. Maximum Generating Unit loading rates **from synchronizing under following conditions:**									
o Hot start	Min								
o Warm start	Min								
o Cold start	Min								
5. Maximum Generating Unit de-loading rate	MW/Min								

6. Minimum interval between de-synchronizing and synchronizing a Generating Unit (off-load time)	Min	
Gas Turbine Generating Units		GC 8 SOPP7
1. Minimum notice required to synchronize	Min	
2. Minimum time between synchronizing different Generating Units at a Generating Facility	Min	
3. Minimum block Load requirement on **Synchronizing**	MW	
4. Maximum Generating Unit loading rates from synchronizing for		
o Fast start	Min	
o Slow start	Min	
5. Maximum Generating Unit de-loading rate	MW/Min	
6. Minimum interval between de- **synchronizing and synchronizing a Generating Unit**	Min	

SCHEDULE X – SCHEDULING AND DISPATCH DATA

Generating Facility Name: ____

The following details are required from each Generator in respect of each Generating Unit.

Data Description	Units	Data Category	Generating Unit and Generating Facility Data						
			U1	U2	U3	U4	U5	U6	GF
Generating Unit Availability Notice		GC 10 GC 8. DSC 3 SOPP 7							
1. Generating Unit Availability									
o Power Capacity	MW								
o Start time	date/time								
2. Generating Unit unavailability									
o Start time	date/time								
o End time	date/time								
3. Generating Unit initial conditions									
o Time required for Notice to Synchronize	Hrs.								
o Time required for start-up	Hrs.								
4. Maximum Generation increase in output above declared Availability	MW								
Generating Unit Availability Notice		GC 8.1 DSC 3 SOPP 7							

1. Generating Unit Availability	
Power Capacity	MW
Start time	date/time
2. Generating Unit unavailability	
Start time	date/time
End time	date/time
3. Generating Unit initial conditions	
Time required for Notice to Synchronize	Hrs.
Time required for start-up	Hrs.
Maximum Generation increase in output above declared Availability	MW
Any changes to Primary Response and Secondary Response characteristics	
Scheduling and Dispatch Parameters	GC 8 GC 8.1
1. Generating Unit Availability	
Description	
Start date	
End date	
Active Power	MW
2. Generating Unit synchronizing intervals	
Hot time interval	Hrs.
Off-load time Interval	Hrs.
3. Station Generating Unit de-synchronizing intervals	Hrs.

4. Generating Unit basic data		
Minimum Generation	MW	
Minimum shutdown time	Hrs.	
5. Generating Unit two shifting limitation		
6. Generating Unit minimum on time	Hrs.	
7. Generating Unit Synchronizing Generation	MW	
8. Generating Unit Synchronizing groups		
9. Generating Unit run-up rates with breakpoints	MW/min	
10. Generating Unit run-down rates with breakpoints	MW/min	
11. Generating Unit loading rates covering the range from Minimum Generation to Maximum Output	MW/min	
12. Generating Unit de-loading rates covering the range from Maximum Output to Minimum Generation		
Generating Unit Merit Order Data(*)		GC 4
Fuel data		
Heat Rate data		

SCHEDULE XI – GENERATOR OUTAGES DATA

Generating Facility Name: ____

The following details are required from each Generator in respect of each Generating Unit.

Data Description	Units	Time Covered	Update Time	Data Category
Provisional Outage Programme				DSC 3
1. Generating Units concerned	ID	Year 2 to 3	End Oct	GC 8.1 DSC 3
2. Active Power not available as a result of Outage	MW	Year 2 to 3	End Oct	EI 1.11 SOPP 19
3. Remaining Active Power of the Facility	MW	Year 2 to 3	End Oct	
4. Duration of Outage	Weeks	Year 2 to 3	End Oct	
5. Start date and time or a range of start dates and	Date Hrs.	Year 2 to 3	End Oct	
System Operator issues Provisional Outage Programme to Users		Year 2 to 3	End Sept	
Agreement on Provisional Outage Programme	Text	Year 2 to 3	End Oct	
Final Outage Programme				DSC .3.3
1. Generating Units concerned	ID	Year 1	End Oct	GC 8. DSC 3 SOPP 19
2. Active Power not available as a result of Outage	MW	Year 1	End Oct	DSC 3
3. Remaining Active Power of the Plant	MW	Year 1	End Oct	
4. Duration of Outage	Weeks	Year 1	End Oct	

5. Start date and time or a range of start dates and times	Date Hrs.	Year 1	End Oct	
System Operator issues draft Final Outage Programme to Users		Year 1	End Sept	
System Operator issues Final Outage Programme to Users	Text	Year 1	End Oct	
Short Term Planned Maintenance Outage				GC 8.
1. Generating Units concerned	ID	Year 0	5 Days before	DSC 3.3 SOPP 19
2. Active Power not available as a result of Outage	MW	Year 0	5 Days before	
3. Remaining Active Power of the Facility	MW	Year 0	5 Days before	
4. Duration of Outage	Weeks	Year 0	5 Days before	
5. Start date and time or a range of start dates and times	Date Hrs.	Year 0	5 Days before	
System Operator issues draft Final Outage Programme to Users		Year 1	End Sept	
System Operator issues Final Outage Programme to	Text	Year 1	End Oct	
Short Term Planned Maintenance Outage				GC 8.
1. Generating Units concerned	ID	Year 0	5 Days before	DSC 3.3 SOPP 19
2. Active Power not available as a result of Outage	MW	Year 0	5 Days before	
3. Remaining Active Power of the Facility	MW	Year 0	5 Days before	
4. Duration of Outage	Weeks	Year 0	5 Days before	

5. Start date and time or a range of start dates and times	Date Hrs.	Year 0	5 Days before

SCHEDULE XII – SYSTEM OPERATOR INFORMATION TO USERS

The System Operator will provide Users and prospective Users the following data related to the Transmission System.

Code	Description
TCC 5.3	Operation Diagram
TC 5.3	Site Responsibility Schedules
DSC 3.3	Demand
	The System Operator will notify each User no later than the [end of October] of each calendar year, for the current calendar year and for each of the following 3 calendar years
	1. The date and time of annual peak of Transmission System demand at Annual Maximum Demand Conditions
	2. The date and time of annual minimum Transmission System demand at Average Conditions
	Transmission System Data including
TC 7.4.11	
	Network Topology and ratings of principal items of equipment
	Positive, negative and zero sequence data of lines, cables, transformers etc.
	Generating Unit electrical and mechanical parameters
	Relay and protection data

SCHEDULE XIII – METERING DATA

Data Description	Responsible Party	Data Category
Interconnection and Metering Point reference details for both Delivery Point and Actual Metering Point		EI 4.7
Data communication details when communication systems are used		
Data validation and substitution processes agreed between affected Parties		

Supply Code

SC

SC 1 INTRODUCTION TO THE CODE

In exercise of powers conferred by Section 47-(1) of the Jamaica Electricity Act 2015 and all other powers enabling it in that behalf, the Office of Utilities Regulator has developed the "Electricity Supply Code".

SC 1.1 Scope

This Code details the obligations of a supply licensee and Customers vis-à-vis each other and specifies the set of practices that shall be adopted by the supply licensee to provide efficient, cost effective and customer friendly service to the Customers.

This Code shall be applicable to:

The supply licensee and all consumers in the Island of Jamaica as covered under the Act.

SC 1.2 Structure of the Supply Code

The Supply Code consists of 13 Sections and Appendices as follows;

Section 1	Introduction to the Code
Section 2	System of Supply and Classification of Consumers
Section 3	New Connections
Section 4	Customers with Embedded Generation
Section 5	Point of Supply Delivery, Licensee's Equipment in Premises
Section 6	Wiring and Apparatus in Consumer's Premises
Section 7	Contract Demand and Agreement (Tariff Design
Section 8	Metering and Billing
Section 9	Customer Providing Demand Response (Reserved)
Section 10	Payment and Disconnection
Section 11	Back Billing and Irregularities
Section 12	Planning
Appendices	

SC 2 SYSTEM OF SUPPLY AND CLASSIFICATION OF CONSUMERS

SC 2.1 System of Supply

The declared frequency of the Alternating Current (AC) shall be 50 cycles per second.

The declared voltage of the AC supply is as follows:

Low Voltage (LV);

a. Single Phase: 220 volts between phases.

b. Single Phase: 110 volts between phases and neutral.

c. Three Phase: 220 volts between phases with single phase at 110 volts or 220 volts

d. Three Phase: 415 volts between phases with single phase at 240 volts

e. Three Phase: 415 volts between phases with single phase at 110 volts.

Three phase service supplied under a general service rate or power rate that includes incidental lighting will be given under the following conditions;

a. at 220 volts 3-phase with single phase at 110 or 220 volts.

b. at 415 volts 3-phase with single phase at 240 volts.

c. at 415 volts 3-phase with single phase at 110 volts in which case Consumer will be required to furnish the necessary transformer from one or other of the available service voltages.

415/240 volt supplies will only be furnished to installations exceeding 50 kW of Demand or 75 H.P. of connected load where such supply is taken from an individual transformer or is available from an existing supply of similar characteristics.

Only customers already furnished with a supply at 440 volts 3-phase may be permitted to increase their power requirements at this voltage provided the additional equipment is being installed at the same location. Single phase loads must be substantially balanced over the 3-phases but a single phase load, provided it does not exceed 10% of the 3-phase load, may be taken from one phase.

The Licensee shall design and operate a Distribution System in conjunction with the Transmission System. The Licensee shall not permit the voltage at the point of supply to the Consumer to vary from the declared voltage which is:

In the case of Low Voltage -- by more than 5% on either side.

In the case of Medium Voltage up to 24 kV -- by more than 5% on the higher side or by more than 5% on the lower side

SC 2.2 Customer classification

The classification of Consumers, tariff and conditions of supply applicable to each category shall be as determined by the OUR from time to time.

SC 3 NEW CONNECTIONS

SC 3.1 Licensee's Obligation to Supply

The supply licensee shall, on an application by the owner or occupier of any premises, provide a supply of electricity to such premises subject to the Standards specified in the Codes provided:

the supply of power is technically feasible;

the Customer has observed the procedure specified in this Code;

the Customer has entered into a contract with the supply licensee (in such form as may be established by the licensee from time to time with the approval of the Office or otherwise entered into pursuant to section 14 of the Office of Utilities Regulation Act) for the supply of electricity to the subject premises and provided such documentation as required by the supply licensee;

the Customer has provided the supply licensee with certification for the wiring of the premises from the Electrical Inspector; and the Customer agrees to bear the cost of supply and services as specified.

The supply licensee shall publish the following codes of practice:

a code of practice, approved by the Office, setting out, in respect of connections within 100 metres of an electricity distribution line and not requiring transformation, forming part of the System, the standard terms and conditions for connection with a schedule of its charges. The code of practice shall include a methodology indicating the principles by which the charges have been calculated.

a code of practice, approved by the Office, setting out, in respect of a connection at a distance greater than 100 metres from an electricity distribution line forming part of the System (complex connections) the basis upon which charges for complex connections will be made in such details so as to enable any person to make a reasonable estimate of the charges to which it would become liable for the provision of a connection.

such codes of practice as the Office directs from time to time in relation to various matters that affect the Customers.

Any connection of a Customer to the electricity distribution line shall be subject to the terms and conditions and codes of practice developed and published by the distribution licensee pursuant to the Distribution Code, including Complex Connections, design and build, installations within a subdivision and underground installations

SC 3.2 Temporary Power Supply

Any person requiring power supply for purpose that is temporary in nature, may apply to the supply licensee for temporary power supply. The form and requirements to be satisfied shall be determined by the supply licensee.

If the supply licensee determines that the supply is feasible, the supply licensee shall advise the applicant of the charges to be paid for the cost of providing the requested temporary supply including laying and dismantling the extension work, service line, meter, etc., together with the charges for the estimated consumption during the period of supply applied for and the rental of equipment & material and the disconnection of the supply. All the charges shall be payable in advance. The applicant shall be bound by such terms and conditions as determined by the supply licensee in respect the temporary supply.

SC 3.3 System of Supply and Metering

If the supply licensee owns and installs more than one metered supply, except for the convenience of the Licensee, on the Consumer's premises, the rate for service furnished through each metered supply shall be determined as if such services were rendered to a separate Consumer.

The electrical energy supplied to a Consumer will be for the use of the Consumer only and shall not be for resale either separately or through sub-metering to another or others without the written consent of the Licensee.

The supply licensee may, under certain conditions and on the written request of the Consumer, shall permit the installation of one or more sub-meters for information purposes and not for resale. In such cases the meters shall be owned supplied and installed by the Consumer who will be solely responsible for reading and maintaining them.

The meter at the point of delivery will be the property of the supply licensee and will be tested at regular intervals. The Licensee at any time, upon the written or verbal request of a Consumer, will test the meter of such Consumer, provided only one such test shall be made free of charge within a twelve month period, and the Consumer shall pay the cost of any additional tests within this period unless the meter is shown to be inaccurate in excess of 2%.

In the event of the stoppage or the failure of any meter to register, the Consumer will be billed for such period on an estimated consumption based upon his use of electrical energy in a similar period of like use.

In the event of any registration inaccuracy in excess of 2%, the account shall be adjusted to allow for the payment by the customer of charges for the energy consumed based on the customers' use of electrical energy during a similar period of like use provided that in no case shall the account be adjusted for a period exceeding six months prior to the date of the adjustment. No part of a minimum charge will be refunded.

SC 3.4 Applicable Rates

The, rates applicable to each category of Customers shall be as determined by the Office from time to time and published in the rate schedule. This Section shall not apply to Customers with whom the supply licensee has entered into a special contract pursuant to section 14 of the Office of Utilities Regulation Act.

SC 4 CUSTOMERS WITH EMBEDDED GENERATION

SC 4.1 Connection Requirements

The embedded generator must be a customer of the licensee and its rights and obligations shall be governed by the terms and conditions of the contract entered into with the licensee. The embedded generator shall comply with the requirements of the Distribution and Generation code as applicable.

SC 4.2 Net Billing and Independent Power Producers

The supply licensee shall purchase electricity from independent power producers and persons who have entered into a net billing arrangement, for transmission and distribution through the System. Such purchases are governed by a SOC and a Power Purchase Agreement respectively, both of which are approved by the Office.

The supply licensee shall have an obligation to connect to independent power producers and persons who have entered into a net billing arrangement, where a Power Purchase Agreement or SOC, respectively, has been executed, save where both the supply licensee and the Government Electrical Regulator agree that the respective connection will compromise the safety and protection of the System.

Based on the nature of Net Billing arrangements supplemental power will be needed from the Grid from time to time, and on occasion they will have excess energy available for sale to the Grid. These installations will be allowed to exchange power with the national grid under a net billing arrangement which involves the following:

The installation of up to two (2) meters at the premises where the renewable energy facility is located. In the case of two (2) meters, each meter will measure energy flow in opposite directions. One meter will account for flows from the supply licensee to the Customer's premises and the other from the generation facility at the Customer's premises to the supply licensee. In the case of the installation of a single meter, that meter will have the capability to measure energy flows in both directions.

The supply licensee will be responsible for the installation and maintenance of the meters. Meter costs will be the sole responsibility of the person entering into a Net Billing arrangement.

A SOC to be executed by the supply licensee and the customer, which will specify the rate fixed by the Office at which the Customer will sell energy to, and purchase energy from the Grid. These rates will be verified by the Office and published in the print media and on its website from time to time.

SC 4.2.2 Facility Licensing

Persons wishing to sell electricity under a net billing arrangement to the supply licensee must therefore first obtain a licence from the Minister and enter into a SOC with the supply licensee before their facility can be connected to the Grid .

SC 4.2.3 Eligible Licensee Customers

Participation in the net billing arrangement is open to residential and commercial Customers of supply licensee who generate their own electricity using a facility which:

has a capacity of less than or equal to 100kW in the case of commercial Customers or less than or equal to 10kW in the case of residential Customers;

uses renewable technologies as its primary source of power; and

complies with all relevant technical specifications and standards as are set out in the SOC as may be amended from time to time.

SC 5 POINT OF SUPPLY DELIVERY, LICENSEE'S EQUIPMENT IN PREMISES

SC 5.1 Point of Supply Delivery

The point of delivery is defined as the point or place at which the Licensee delivers to the Consumer the supply of electricity to be used by the Consumer as follows:

a. Supply furnished at secondary voltage will be delivered at the Consumer's end of the incoming service wires at the point where such service wires are connected to the Consumer's premises.

b. Supply furnished at primary voltage will be delivered at the high tension side of the main transformer bank, which is to be considered as the point of supply delivery.

The point of supply should be such that meter/metering equipment should be visible and easily accessible from outside the premises.

SC 5.2 Dedicated Feeder

If a Customer is or has been provided a separate feeder at his request in addition to the feeder from which supply is provided to the Customer by the Licensee, such additional separate feeder shall be termed as "Dedicated Feeder". On receipt of such request, the Licensee will check the feasibility based on merit of providing a Dedicated Feeder to the Customer's premises. If found feasible, the Customer will be provided with a Dedicated Feeder and the Customer will be liable to pay additional charges as provided for the recovery of expenses and other charges for providing electric line or plant used for the purpose of giving supply. The Dedicated Feeder shall be extended from the power substation to the Customer's point of supply delivery.

SC 5.3 Supply Licensee's Equipment in Customer's Premises

The supply licensee shall have the right to install and maintain in convenient and suitable places on the premises of the Customer free of charge, all transformers, meters, wires and other equipment necessary for the satisfactory supply of electricity to the Customer. All transformers, meters, wires and other equipment furnished by the supply licensee shall remain its property and the Customer shall be liable for all damages to or loss of the supply licensee's property located on the Customer's premises, unless such damage or loss is caused by the negligence of the supply licensee.

The supply licensee shall have the right of free access to the premises of any Customer and every part thereof at all reasonable times during the period of the contract and during the period that electricity is supplied and as long as any of the property of the supply licensee remains on the said premises, for the purpose of installing, inspecting, repairing, replacing and removing all transformers, meters, wires, and other equipment of the supply licensee, and of inspecting and examining any electrical wiring, appliances and equipment of the Customer connected thereto and for any other lawful purpose.

The meter, cut-out/ MCB, service mains and other equipment belonging to the supply licensee, shall be handled or removed by an authorized /representative of the supply licensee only. The seals, which are fixed on the meters /metering equipment, load limiters and the supply licensee's apparatus, shall not be tampered, damaged and broken. The responsibility for the safe custody of supply licensee's Equipment and seals on the meters/metering Equipment within the Customer's premises shall be the responsibility of the Customer.

In the event of any damage caused to the supply licensee's equipment in the Customer's premises by reason of any act, neglect or default of the Customer or his employees/ representatives, the cost thereof as claimed by the supply licensee shall be payable by the Customer. If the Customer fails to do so on Demand, it shall be treated as a contravention of the terms and conditions of supply Agreement and the supply shall be liable to be disconnected after due notice. The Customer shall however be liable to pay the charges for the balance initial period of the Agreement.

The supply licensee shall maintain the meters and equipment, installed at Customer's premises from where the electricity is supplied to the Customer.

SC 5.3.2 Failure of fuse / supply:

Should the Licensee's service fuse or fuses fail, at any time, notice thereof should be sent to the Licensee's local office. Only authorized employees possessing the photo identity card of the Licensee are permitted to replace these fuses in the Licensee's cutouts. Consumers are not allowed to replace these fuses. The Licensee should not allow its employees to carry out any repairs in the Consumer's installations.

The supply licensee shall take all reasonable precautions to ensure continuity of supply of electrical energy to the Consumer but shall not be responsible for or be liable to the Consumer for any loss to him or damage to his plant and equipment due to interruptions in supply of electrical energy due to Force Majeure Conditions.

The supply licensee shall always be entitled to temporarily discontinue the supply for such period as may be necessary for maintenance or for any other reasons, subject to reasonable advance notice being given in this behalf, with the object of causing minimum inconvenience to the Customer.

SC 6 WIRING AND APPARATUS IN CONSUMER PREMISES

SC 6.1 Wiring in Consumer's Premises

For the protection of the Customer and the public in general, it is necessary that all wiring and electrical equipment shall conform to the rules and regulations made by the appropriate Minister under the provisions of the Act, as well as any further requirements of the supply licensee or the Government Electrical .Regulator. The Licensee may refuse to make connection or give service if it shall be advised that an electrical installation does not conform to such requirements or these Terms and Conditions. The Customer shall not materially increase his load without first notifying the Licensee and obtaining its consent.

SC 6.1.1 General Wiring Conditions:

Mains:

The Customer's mains shall, in all cases, be brought back to the Licensee's point of supply and sufficient cable shall be provided for connecting up with the Licensee's apparatus.

Switches and Fuses:

The Customer shall provide proper linked quick-break main switches of requisite capacity to carry and break current in each conductor near the point of commencement of supply. The switches in the Customer's premises shall be on the live wire and the neutral conductor shall be marked for identification where it leaves the Customer's main switch for connecting up to the meter. No single pole switch or cut-out should remain inserted in any neutral conductor.

Balancing of load:

The Customer taking three-phase supply shall balance his load between the phases.

Earthing:

Gas and water pipes shall not be used for earthing purposes. All wiring shall be kept as far as possible away from gas and water pipes.

Plugs:

All plugs shall be provided with switches on the live wire and not on the neutral.

SC 6.1.2 Domestic appliances:

For the safety of the wiring at the Customer's premises, separate circuit for the equipment other than lighting and fan load like heaters, geysers, air-conditioners, oven, etc. shall be run with adequate size of wire from the main distribution board of the Customer. Wall plugs used on the circuits for domestic appliances shall be of the three-pin type, the third pin being connected to "earth". Two pin plugs shall not be allowed. All appliances used in any location must be effectively earthed.

SC 6.1.3 Apparatus interfering with Licensee's system

The Licensee may discontinue the supply, if the Customer installs any instrument, apparatus that are likely to affect adversely, the supply to other Customers. Supply shall be restored on taking appropriate remedial action by the Customer to the satisfaction of the Licensee.

SC 6.1.4 Customer's Apparatus

The apparatus/ appliances/ gadgets used by Customer should conform to the standards and specifications prescribed by the Bureau of Standards or equivalent.

a. The Customer shall install only such motors or other apparatus or appliances as are suitable for operation with the character of the service supplied by the Licensee, and which shall not be detrimental to same, and the electrical energy must not be used in such a manner as to cause voltage fluctuations or disturbances in the Licensee's Distribution System.

b. It is the responsibility of the Customer to provide the necessary equipment to protect all motors and other apparatus or appliances from damage resulting from Low Voltage, single phasing conditions, etc.

c. All apparatus used by the Customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and the proper balancing of phases. Motors that are frequently started, or motors arranged for automatic control, must be of a type to give maximum starting torque with minimum current flow.

Failure to comply with these Regulations will render the Customer liable for disconnection forthwith.

SC 6.1.5 A.C. Motor Installations

The Licensee's requirements regarding the starting of induction motors are as follows:

a. Motors up to but not including 10 H.P.

   The motors may be started directly on the lines without the use of a current limiting starter.

b. Motors from 10 H.P. to 15 H.P. inclusive

If these motors are started without load it is permissible to start them directly on the lines without the use of current limiting starter. If required to start under load, a current limiting starter must be installed.

c. Motors over 15 H.P.

All motors in this category whether of squirrel cage or slip ring type must be equipped with current limiting starters of a type acceptable to the Licensee. In case of violation of this rule, service may be discontinued by the Licensee until such time as the Customer has conformed to the Licensee's terms and conditions as regards motors and starting equipment. Such suspension of service by the Licensee shall not constitute a cancellation of Contract. Notwithstanding any of the above conditions, the Licensee reserves the right to review each individual case and insist if necessary on the correct type of motor and starting equipment being installed for any specific motor load.

SC 6.2 Power Factor of Apparatus

a. Gaseous tube installations shall be equipped if necessary with condensers of sufficient capacity to maintain at least 85% Power Factor.

Fluorescent lighting installation shall be of the Power Factor corrected type to maintain at least 85% Power Factor.

b. In the case of other apparatus or equipment taking a highly intermittent or fluctuating supply of energy and /or low Power Factor, the Licensee will require the Customer to furnish and install at his own expense the corrective equipment necessary to stabilize the intake and maintain at least 85% of Power Factor.

c. The Licensee reserves the right to refuse or discontinue service to installations that do not meet the above Power Factor and other requirements until the conditions have been rectified.

SC 6.3 Inspection and Testing of Customer’s Installation

Before any wiring or apparatus in the case of Low Voltage Customer, and any transformer, switchgear or other electrical equipment in the case of High Voltage Customer is connected to the system, it shall be subject to inspection and approval of the Licensee and no connection shall be made without the Licensee’s approval. In addition, all High Voltage installations will have to be approved by a Licensed Electrical Ienspector.

Upon receipt of the test report, the Licensee will notify to the Customer the time and day when the Licensee proposes to inspect and test the installation. The

Customer shall ensure that the Licensed Electrical Contractor or his representative, technically qualified, employed by him is present at the time of inspection to furnish to the Licensee any information concerning the installation required by him. The Licensee shall provide a copy of the inspection report to the Customer and obtain the acknowledgement of the Customer.

Manufacturer's test certificate in respect of all Medium Voltage apparatus shall be produced, if required.

The Licensee shall not connect the conductors and fittings on the Customer's premises with its works unless it is reasonably satisfied that the connection will not at the time of making connection cause a leakage from the installation or apparatus of a magnitude detrimental to safety.

If the Customer's installation is found to be not safe for connection, the Licensee shall advise the Customer in writing specifying the defects to be rectified. On receipt of intimation of rectification of defects, the Licensee shall retest the installation.

The Licensee shall levy no charge for the first test. Subsequent tests, necessitated due to faults found at the initial test shall be charged for in accordance with the rates approved by the Government Electrical Regulator. The Licensee will not accept any responsibility with regard to the maintenance or testing of wiring on the Customer's premises.

SC 6.4 Extensions and Alterations

No electrical installation work, including additions, alterations, repairs and adjustments to existing installations, except such replacement of lamps, fans, fuses, switches, Low Voltage domestic appliances and fittings as in no way alters its capacity or character, shall be carried out upon the premises of or on behalf of any Customer, for the purpose of supply to such Customer except by a licensed electrical inspector. Extension or alterations of load to all high-tension installations will have to be approved by the icensed Electrical Inspector.

If as a result of such proposed extensions and alterations, there is possibility of an increase in connected load or Contract Demand over sanctioned connected load or Contract Demand, the Customer shall take steps to submit requisition for additional supply. Failure to regularize the increase in connected load or Contract Demand may not only result in billing at other rates, as provided for under the rules, but may also result in disconnection of supply after due notice.

SC 6.5 Access to Premises for Inspection of Customer's Installation

The authorized persons of the Supply licensee are entitled, at any reasonable time and on informing the occupier of their intention, may enter the premises of the

Customer to which energy is supplied, for the purpose of inspecting and reading meters on the Consumer's premises, for disconnecting supply, for removing the Supply licensee's apparatus, for testing, repairs, replacing, altering and maintenance of its property or for doing all things necessary or incidental to proper continuance and maintenance of supply to the Consumer. All such persons visiting Customer premises must carry photo-identity cards issued by the Supply licensee and shall produce the same to the Customer or the occupier before entering the premises. The Customer should immediately check with the Supply licensee if the credentials of representatives are in question.

The Supply licensee or his authorized person shall be entitled to enter the premises immediately after informing the Customer, for checking unauthorized use of energy, unauthorized additions and alterations to equipment, theft and misappropriation of energy, diversion of power, by-passing or tampering of the meter, or for general inspection and testing. On detection of unauthorized use of energy, unauthorized additions and alterations to equipment, theft and misappropriation of energy, diversion of power or bypassing or tampering of the meter the Supply licensee may take actions as per prevailing laws.

If the Customer does not provide reasonable facility to the Supply licensee to enter the premises for the reasons stated above, the Supply licensee may give notice in writing to the Customer, of its intention to discontinue the supply. If the Customer still does not provide access, the Supply licensee shall be entitled to discontinue supply to the Customer.

SC 6.6 Rating of Installations

The connected load of domestic category of Customers shall be determined as per the load details of the equipment. If the supply licensee has reasons to believe that a particular domestic connection or a group of domestic connections might be involved in unauthorized abstraction of power, the supply licensee may conduct a survey of the Customer's premises.

Where for any reason, it is not possible to determine the maximum Demand, power factor or any other electrical quantity in respect of an installation, the supply licensee shall determine such quantities periodically by rating/re-rating, which shall be binding on the Customer.

SC 6.7 Generator in the Customer's Installation

Operations of the Customers' Generating unit in the Customer's premises running parallel with the supply licensee's system is permissible only with the written consent of the supply licensee. The supply licensee may levy parallel operation charges with the approval of the Office.

Where no such consent has been given, the Customer shall arrange the plant, machinery and apparatus of his generating units, including an extension of or addition to the same, to operate in an isolated mode and the generator, in no case, should get connected to the supply licensee's system. The supply licensee, on advising the Customer, can enter the premises and inspect the arrangement to ensure that at no time the generating units get connected to its system.

Where consent has been given for parallel operation, the Customer shall arrange his installation to protect it from disturbances in the supply licensee's system. The Customer should also ensure that his supply does not get incorrectly connected to the supply licensee's system. The supply licensee shall not be liable for any damage caused to the Customer's plant, machinery and apparatus on account of such parallel operation, or any adverse consequence arising thereof. For parallel operation with the Grid, the Customer shall have to follow the provisions of the Generation Code, Transmission Code, Distribution Code and the Dispatch Code, and other relevant regulations. The actual operations shall be carried out in coordination with the supply licensee.

In case the Customer's supply gets extended to the supply licensee's system from a generator or inverter or from any other source, without appropriate approval from the supply licensee, causing damage to the supply licensee's apparatus or to human life, the Customer shall be liable for the same and shall duly compensate the supply licensee for all losses caused to the supply licensee or to the supply licensee's other Customers.

SC 6.8 Harmonics

If the Supply Licensee detects and proves to the Customer that the Customer's system is generating harmonics, the supply licensee shall request the Consumer to install an appropriate harmonic filter. The Customer shall install such filters within a period of six months, failing which the supply licensee may levy penalty on the Customer as decided by the Office besides disconnection.

SC 7 CONTRACT DEMAND AND AGREEMENT

SC 7.1 Contract Demand

SC 7.1.1 Low Voltage Consumers without Maximum Demand based rates

The Contract Demand for Low Voltage Customers without MD based (two part) rate will be the connected load of the premises as provided in the Agreement entered into between the Customer and the supply licensee.

Low Voltage Customers with MD based rate and all MV Customers

The Contract Demand shall be as provided in the Agreement entered into between the Customer and the supply licensee. However, in case of LT connections with Demand based rate, the supply licensee shall indicate in the agreed connected load and Contract Demand.

SC 7.1.2 Procedure for Enhancement of Contract Demand

Applications for enhancement of load shall be submitted to the supply licensee in the specified forms along with fee as specified for Recovery of expenses and other charges for providing electric line.

The supply licensee shall examine the feasibility of supply of the enhanced load and advise the Customer:

a. Whether the additional power can be supplied at the existing voltage or at a higher voltage.

b. Addition or alterations, if any, required to be made to the system and the cost to be borne by the Customer.

c. Amount of additional security deposit, cost of additional infrastructure and the system strengthening charges or capacity building charges, if any, to be deposited.

d. Change in the classification of Customer, if required.

The application for enhancement of the Contract Demand will not be accepted if the Customer is in arrears of payment of the supply licensee's dues. However, the application may be accepted if the payment of arrears due from the Customer has been stayed by a Court of law.

If the supply of enhanced load is feasible, the Customer shall:

a. Furnish work completion certificate of Customer’s installation and Test report from a Licensed Electrical Contractor where alteration of installation is involved.

b. Furnish Letter of approval for the electrical installation of the Customer from the Government Electrical Regulator in case of medium or high voltage connection, if required.

c. Pay additional security deposit, cost of addition or alteration required to be made to the system, if any, and the other applicable charges.

d. Execute a supplementary Agreement.

In cases where LT Demand based rate is applicable and the Customer desires to enhance his connected load without any change in Contract Demand, he shall make an application to the supply licensee along with the details of load of existing equipment and equipment that are proposed to be connected,. The supply licensee shall inspect the premises of the Customer and shall verify the connected load and inform the Customer as to whether the connected load is within the ceiling prescribed. In case any change is required in the applicability of rate, the supply licensee shall inform the Customer in writing within thirty (30) days of receipt of application. The supply licensee & Customer shall enter into Agreement for enhancement of connected load, if Contract Demand and applicability of the tariff is not required to be changed and the list of equipment giving details of connected load shall form a part of the Agreement. The Customer shall not be required to pay any additional security deposit in such case. However, necessary charges towards Supply Affording Charges as per recovery of expenses and other charges for providing electric line or plant used for the purpose of giving supply shall be payable.

If no addition or alternate to the system including new/ alternate metering arrangement is required, the enhanced load will be released immediately after completion of the requisite formalities. If the system needs any alternate or addition, the procedure as given for a new connection shall be followed.

Where the Customer

a. desires to enhance the Contract Demand beyond the maximum permissible limit as specified in this Code he shall be required to switch over to higher voltage level ;

b. desires to switch over to higher voltage having existing Contract Demand eligible for higher voltage load limits , the supply affording charges and other charges as specified for recovery of expenses and other charges for providing electric line or plant used for the purpose of providing supply shall be payable. .

SC 7.1.3 Procedure for Reduction of Contract Demand

If the Customer so desires, one time reduction in the Contract Demand shall be allowed within the term of agreement. The reduction in Contract Demand shall be limited to 50% of the Contract Demand as provided in the agreement in force at the time of making application provided the requested reduction in Contract Demand shall not be less than the specified minimum Contract Demand for a particular voltage class as specified in Section 3 of this Code. Supply Affording Charges and other applicable charges once paid shall not be refundable.

Application for reduction in Contract Demand shall be submitted to the supply licensee in the specified format. A Test report from a competent Licensed Electrical Contractor shall be submitted by the Customer before reduction in Contract Demand is allowed by the supply licensee. .

On receipt of application for reduction in Contract Demand, the supply licensee shall take the following steps:

The supply licensee shall consider the grounds stated in the application and allow the application or convey the reasons for non-consideration in writing within a period of fifteen (15) clear days.

Where the application is not decided by the supply licensee within the fifteen (15) clear days period, the Customer may, by a written notice to the supply licensee, draw its attention to the matter and if no decision is communicated to him within a further fifteen (15) clear days after the delivery of such notification, the permission of reduction of Contract demand shall be deemed to have been granted with effect from the next working day after expiry of such notice period.

Where the reduction in Contract Demand is allowed, the same shall take effect from the first day of the month following the month in which the decision for reduction in Contract Demand is communicated.

After the expiry of the initial period of agreement, the Customer will be entitled to reduce Contract Demand of his connection limited to the minimum Contract Demand for a particular voltage class as specified in this Code. Further, such request when made to the supply licensee shall come into effect from the date of completion of formalities such as execution of agreement etc. Any subsequent request for reduction in Contract Demand can also be made to the supply licensee after expiry of at least one (1) year from the date of effect of such reduction in Contract demand.

When reduction of Contract Demand is agreed to, the Customer shall execute a supplementary agreement. The effect of reduction in Contract Demand shall be passed on to the Customer after finalization of agreement by the supply licensee.

The request of the Customer for reduction in Contract Demand of his connection shall not be refused by the supply licensee on the ground that there are dues payable to the supply licensee against the connection.

The Customer shall not be entitled to get refund of new connection charges/supply affording charges on account of such reduction in Contract Demand. However, if the Customer subsequently after reduction in Contract Demand requires enhancing the Contract Demand again, he shall be required to pay supply affording charges etc. as applicable at the time of such request.

SC 7.2 Agreement

SC 7.2.1 Rephrasing/Rescheduling of Contract Demand

In case the Customer has executed Agreement for Contract Demand in phases and requests for rephrasing/rescheduling of Contract Demand, the Customer may be permitted provided that such rephrasing/rescheduling of Contract Demand shall not result in reduction of Contract Demand.

The Customer is required to apply for rephrasing/rescheduling of Contract Demand at least one month prior to the date of commencement of Contract Demand to be rescheduled.

This facility shall be allowed to the Customer only once during the initial period of Agreement.

SC 8 METERING & BILLING

SC 8.1 Requirement of Meters

No new connection shall be given without a meter and cut-out or a Miniature Circuit Breaker (MCB) or Circuit Breaker (CB) of appropriate specification complying with relevant standards. The supply licensee should procure sufficient quantity of suitable meters/metering equipment for new service connections, providing meters for unmetered connections and replacement of stopped/defective meters/ metering equipment.

All Customers shall have to accept the installation of an appropriate metering device, load-limiter, tamper proof boxes or other apparatus when the supply licensee approaches them to install one, and the Customer shall be required to provide appropriate and suitable site for placement of meter and related equipment to the satisfaction of the supply licensee.

SC 8.2 Supply and installation of Meters

All Customers shall have to accept the installation of an appropriate metering device, load-limiter, tamper proof boxes or other apparatus when the supply licensee approaches them to install one, and the Customer shall be required to provide appropriate and suitable site for placement of meter and related equipment to the satisfaction of the supply licensee.

All metering facilities shall be subject to the approval of the supply licensee. Supply licensee retains the right to refuse service or disconnect an existing service, where it is not satisfied that the facility meets the minimum acceptable standard for installation.

Metering facilities for townhouse complexes, commercial/industrial installations, apartments, plazas, subdivisions, and housing schemes requiring multiple stations, and all meter Centres shall be accessible on a 24-hour basis to supply licensee personnel. All meters shall be clearly identified for emergency, safety and maintenance purposes. Designs for such facilities shall be submitted to supply licensee for approval prior to construction.

Approval requests shall be accompanied by a drawing illustrating full details of supply up to, and including the metering facility. This drawing shall be duly notarized by a Registered Professional Electrical Engineer, licensed to practice in Jamaica.

The placement of meters shall be at the perimeter fence or at the property boundary, and shall be installed such that safe and reasonable access to meters is afforded to the supply licensee personnel on a 24 hour basis. Meters shall be viewable and accessible without the need to enter locked premises.

The placement of meters in locations other than that specified herein shall only be allowed on the prior written permission of supply licensee, and under special, or extenuating circumstances.

All revenue meters for any building shall be installed at a common location and subject to the conditions stated above.

For supply points in excess of 30m from existing supply licensee distribution line, Customers shall make provisions for extensions to provide for service within 30m. Such extensions shall be subject to the supply licensee Line Extension Policy and the conditions outlined in sections SC 2 and SC 3 of this Code.

Wooden poles shall be straight, treated hardwood, with a minimum height of 7.0m above ground. Poles shall be of nominal length of 9m with a minimum top diameter of 150 mm for round wooden pole, and 127 mm x 127 mm for square poles. Poles shall be planted to a minimum depth of 10% of their length plus 0.7m.

A projection out of the wall of at least 13 mm is required for embedded socket-type meters. In the case of existing installations where the meter socket is too deeply embedded, the Applicant will be required to provide a 38 mm x 25 mm deep recess around the socket before re-certification.

All meter sockets, with removable covers, shall be constructed to permit sealing of the covers by supply licensee. Supply licensee shall not install its meters on sockets that do not meet this requirement.

a. A maximum of three (3) revenue meters will be allowed on a wooden pole for overhead service.

b. There shall be a maximum of four (4) revenue meters on a concrete column.

c. Whenever meters are installed on pole there shall be separate conduits for the incoming main and the load line to the Customer's premises.

Identification of potheads & meter sockets

a. Potheads and Meter sockets must be clearly marked so that each pothead can be easily identified with its corresponding meter socket. In the case of condominium and apartments, the meter sockets must be clearly identified with apartment numbers. This identification must be permanent.

b. Supply licensee reserves the right to terminate Contracts where there is tampering or removal of identification marks. The Government Electrical Regulator shall give no consideration for a new Contract without re-certification.

Meters and meter-stations shall have an unimpeded front clearance of 1500mm.

Whenever meters are placed in locked cages by the owners for improved security, the metered facility shall meet all requirements of this policy and supply licensee shall provide their own locks. The metering area shall be kept free of stored materials/garbage or other objects that poses an obstruction to the view or access to the meter or metering facilities. Supply licensee personnel shall have unimpeded and unobstructed access to all metering facilities and equipment, to facilitate reading, replacement, maintenance, testing and investigation.

All apartment buildings shall have meter sockets arranged in groups at a common location.

It is the responsibility of the Customer to satisfy supply licensee that metering facilities will be accessible to supply licensee personnel on a 24-hour basis.

Modifications to Existing Installations

Whenever modifications are done to a building infrastructure, or the electrical facilities, then such modification(s) shall meet the requirements of this Code. Approval for the modifications shall be obtained from supply licensee prior to the start of construction and the facility shall be re-certified by the Government Electrical Regulator.

Detection of Irregularity

Whenever any irregularity is discovered on an installation, the irregularity shall be reported to the supply licensee for immediate action. In the case of theft, tampering, or incorrect configuration, the Customer shall be required to modify the installation to meet supply licensee policy. These modifications shall first be approved by supply licensee and certified by the Government Electrical Regulator before re-connection.

Requirements for Meter Centres

Whenever meter Centres are used the front cover shall be of a non-removable type or provisions made for sealing the individual covers.

Whenever meters or meter Centres are installed in a locked room, supply licensee shall be provided with copies of keys. The Customer shall further provide a secured facility suitable for storage and easy access for these keys. Suitability shall be established by supply licensee at the time of application.

No new connection shall be given without a meter and cut-out or a Miniature Circuit Breaker (MCB) or Circuit Breaker (CB) of appropriate specification complying with relevant standards. The supply licensee should procure sufficient quantity of suitable meters/metering equipment for new service connections, providing meters for unmetered connections and replacement of stopped/defective meters/ metering equipment.

The supply licensee is authorized to review the status of the meters already installed in the context of upgraded technology becoming available and suitability of the site where meter is placed in the Customer’s premises. The supply licensee may install remote metering device in the Customer premises as per the technical requirements of the specific device and in such cases the Customers shall provide access to the meter through his telephone line. The supply licensee may also install maximum Demand (MD) meter having MD recording feature or such additional features in the Customer’s premises. The supply licensee is also authorized to install ‘check meter’ at one Customer’s location or for a group of Customers. In case the difference in consumption recorded by the ‘check meter’ and the ‘billing meter' is found to be more than permissible limits, the supply licensee shall be free to install the billing meter on electricity pole or pillar boxes after giving

SC 8.3 Testing of Meters

It shall be the responsibility of the supply licensee to satisfy himself regarding the accuracy of the meter before it is installed and m Meters should be tested according to the meter testing standards prescribed and published by the Office.

The meter will be the property of the supply licensee and will be tested at regular intervals. The supply licensee at any time, upon the written or verbal request of a Customer, will test the meter of such Customer, provided only one such test shall be made free of charge within a twelve (12) month period, and the Customer shall pay the cost of any additional tests within this period unless the meter is shown to be inaccurate in excess of two percent (2%).

In the event of the stoppage or the failure of any meter to register, the Customer will be billed for such period on an estimated consumption based upon his use of electrical energy in a similar period of like use.

In the event of any registration inaccuracy in excess of two percent (2%), the account shall be adjusted to allow for the payment by the Customer of charges for the energy consumed based on the Customers' use of electrical energy during a similar period of like use provided that in no case shall the account be adjusted for a period exceeding six months prior to the date of the adjustment.

SC 8.4 Defective Meters

The supply licensee shall have the right to test any meter and related apparatus if there is a reasonable doubt about the accuracy of the meter, and the Customer shall provide the supply licensee necessary assistance in conduct of the test. The Customer shall be allowed to be present during the testing.

A Customer may request the supply licensee to test the meter, if he doubts its accuracy, by applying to the supply licensee along with the requisite testing fee. The supply licensee shall test the meter within 15 days of the receipt of the application and fee. Preliminary testing of electronic meters can be carried out in the premises of the Customers through electronic testing equipment.

In all cases of testing of a meter in the laboratory, the Customer shall be informed of the proposed date of testing in advance, so that he may be present at the time of testing, personally or through an authorized representative. The signature of the Customer or his authorized representative, if present, shall be obtained on the Test Result Sheet.

If a Customer is desirous of getting a meter tested at own cost through an independent laboratory instead of laboratory of supply licensee, the Customer shall have it tested at the laboratory approved by the Office on payment of necessary charges.

SC 8.4.1 Meter Not Recording

The Customer is expected to advise the supply licensee in writing, as soon as he notices that meter has stopped/ is not recording if the situation comes to his notice. The supply licensee shall acknowledge the intimation given by the Customer.

If during periodic or other inspection by the supply licensee, any meter is found to be not recording, or a Customer makes a complaint in this regard, the supply licensee shall arrange to test the meter and if found defective the meter shall be repaired/replaced.

No metering charges towards meter/metering equipment shall be payable during the month in which meter/metering equipment remained defective for more than 15 days in urban area and more than 30 days in rural area.

SC 9 CUSTOMERS PROVIDING DEMAND RESPONSE (RESERVED)

SC 10 PAYMENT AND DISCONNECTION

SC 10.1 Payment

Bills shall be determined by the supply licensee on a monthly basis and rendered to the Customer every month in accordance with the terms of the connection agreement and the rate applied.

Failure to receive a bill will not entitle the Customer to the remission of any charge for non-payment within the time specified. In the case of new connections or disconnections made by the supply licensee during a billing period, Customers' bills for service may be pro-rated.

The Customers are required to make payment of the bills issued to them regularly within due dates.

Every Customer shall be issued a receipt in token of having received the payment. The Customer may also be allowed to make advance payment of future bills, which shall be adjusted in the succeeding months. However, only the regular bill amount shall be adjusted from the advance payment. Before adjusting any other amount, the consent of the Customer shall be sought.

Commercial categories of Customers committing default in the payment of the Billed Amount shall be liable to pay delayed payment surcharge, on the amount outstanding, at rates as per applicable retail supply tariff order.

Disputed/Erroneous Bills

a. In the event of any objection in respect of the Billed Amount, the Customer may make a representation before the supply licensee office. The supply of electricity shall not be cut off if such person deposits, under protest,

   i. an amount equal to the sum claimed from him, or

   ii. the electricity charges due from him for each month calculated on the basis of average charge for electricity paid by him during the preceding six months, whichever is less, pending disposal of any dispute between him and the supply licensee.

b. The representation may be made on plain paper along with the following details:

   i. Name and address of the Customer mentioning telephone number, if any

   ii. Service connection number

   iii. Category of connection

   iv. Facts and relief sought in brief

The designated officer of the supply licensee shall resolve the dispute within a maximum period of seven days from the date of receipt of such written representation.

c. If the supply licensee finds the bill to be erroneous, a revised corrected bill shall be furnished to the Customer indicating the revised due date not less than seven days of the date of delivery of revised bill. Excess amount paid by the Customer, if any, shall be adjusted in the subsequent bill(s).

d. In the event that the original bill was correct, the Customer shall be advised accordingly to pay the balance, if any, with surcharge as applicable as per original bill within 7 days.

e. In case the Customer is not satisfied with the decision of the supply licensee or otherwise, he may approach the Office.

SC 10.2 Disconnection

If a Customer fails in payment of any bill in full, without the approval of the supply licensee, by the due date, the service connection of the Customer shall be liable to be disconnected.

The Customer shall be required to make a written request to the supply licensee if the Customer wishes to get his connection temporarily disconnected for a period up to six months. For duration of temporary disconnection the Customer shall be liable to pay in advance all the monthly charges that are fixed in nature like fixed charge, minimum charge, metering charges etc. The Customer shall also be liable to pay disconnection / reconnection charges to avail the facility of temporary disconnection.

SC 10.3 Reconnection

If service shall have been discontinued for any of the reasons set forth in sub-section 10.2 the following conditions shall be complied with before service is restored:-

a. Any violation of the rules and regulations must be corrected.

b. Satisfactory arrangements for the payment of all bills for service then due must be made and a satisfactory guarantee furnished regarding payment of all future bills.

c. Any dangerous conditions must be removed, and if the Customer had been warned of the condition a reasonable time before the discontinuance of service and failed to remove the dangerous condition, a reasonable fee for reconnection of service may be charged.

d. All bills for service due; including estimated amounts due to supply licensee by reason of fraudulent use or tampering must be paid. A deposit to guarantee the payment of future bills shall be made.

e. A reconnection fee as set out in the Rate Schedule must be paid. This fee may be revised from time to time as approved by the Office.

f. If reconnection of service is requested by the same Customer on the same premises within one year after discontinuance of service the same reconnection fee may be charged.

SC 11 BACK BILLING AND IRREGULARITIES

SC 11.1 Introduction

There shall be a limitation on the ability of the supply licensee to back bill customers under varying conditions and circumstances. The period and circumstances of such period of such back billing shall be established by the licensee and approved by the OUR.

APPENDIX A

SCHEDULE 1 – GUARANTEED STANDARDS

TABLE 1: GUARANTEED STANDARDS - Effective as of January 7, 2015

CODE	FOCUS	DESCRIPTION	PERFORMANCE MEASURE
EGS 1(a)	Access	Connection to supply – New & Simple Installations	New service Installations within five (5) working days after establishment of contract, includes connection to RAMI system. Automatic compensation as of June 1, 2015.
EGS 2(a)	Access	Complex Connection to Supply	From 30m and 100m of existing distribution line (i) estimate within ten (10) working days (ii) connection within thirty (30) working days after payment Automatic compensation as of January 1, 2016.
EGS 2(b)	Access	Complex Connection to Supply	From 101m and 250m of existing distribution line (i) estimate within fifteen (15) working days (ii) connection within forty (40) working days after payment Automatic compensation as of January 1, 2016.
EGS 3	Response to Emergency	Response to Emergency	Response to Emergency calls within five (5) hours – emergencies defined as broken wires, broken poles, fires. Automatic compensation as of June 1, 2016.
EGS 4	First Bill	Issue of First Bill	Produce and dispatch first bill within forty (40) working days after service connection.

			Automatic compensation as of January 1, 2016.
EGS 5(a)	Complaints/ Queries	Acknowledgments	Acknowledge written queries within five (5) working days Automatic compensation as of June 1, 2016.
EGS 5(b)	Complaints/ Queries	Investigations	Complete investigations within thirty (30) working days. Complete investigations and respond to customer within thirty (30) working days. Where investigations involve a 3rd party, same is to be completed within sixty (60) working days. Automatic compensation as of June 1, 2016.
EGS 6	Reconnection	Reconnection after Payments of Overdue amounts	Reconnection within twenty-four (24) hours of payment of overdue amount and reconnection fee. Automatic compensation.
EGS 7	Estimated Bills	Frequency of Meter reading	Should NOT be more than two (2) consecutive estimated bills (where Licensee has access to meter). Automatic compensation as of June 1, 2016.
EGS 8	Estimation of Consumption	Method of estimating consumption	An estimated bill should be based on the average of the last three (3) actual readings. Automatic compensation as of June 1, 2015.
EGS 9	Meter Replacement	Timeliness of Meter Replacement	Maximum of twenty (20) working days to replace meter after detection of fault which is not due to tampering by the customer. Automatic compensation.
EGS 10	Billing Adjustments	Timeliness of adjustment to customer's account	Where it becomes necessary, customer must be billed for adjustment within three (3) months of identification of error, or subsequent to replacement of faulty meter.

			Automatic compensation as of June 1, 2015.
EGS 11	Disconnection	Wrongful Disconnection	Where the Licensee disconnects a supply that has no overdue amount or is currently under investigation by the Office or the Licensee and only the disputed amount is in arrears. Automatic & special compensation.
EGS 12	Reconnection	Reconnection after Wrongful Disconnection	The Licensee must restore a supply it wrongfully disconnects within five (5) hours. Automatic & special compensation.
EGS 13	Meter	Meter change	The Licensee must notify customers of a meter change within one (1) billing period of the change. The notification must include: the date of the change, the meter readings at the time of change, reason for change and serial number of new meter. Automatic compensation as of January 1, 2016.
EGS 14	Compensation	Making compensatory payments	Accounts should be credited within one (1) billing period of verification of breach. Automatic compensation as of June 1, 2015.
EGS 15	Service Disruption	Transitioning existing customers to RAMI System	Where all requirements have been satisfied on the part of the Licensee and the customer, service to existing Licensee customers must not be disrupted for more than three (3) hours to facilitate transition to the RAMI system. Automatic compensation as of January 1, 2016.

Pre-paid Metering Guaranteed Standards

EPMS 1	Service Connection	Transitioning existing customers to pre-paid metering system	Transition to the pre-paid metering service must be completed within fifteen (15) days of establishment of contract.
EPMS 2	Service Disruption	Transitioning existing customers to pre-paid metering system	Except where there is the need for the premises to be re-certified by a licensed electrical inspector, there should be no disruption in customer's service.

1. Wrongful Disconnection

   The standard is defined as follows:

   The Licensee commits a breach where it disconnects a customer's supply that has no overdue amount reflected on the associated account. This standard will also apply to accounts that are under investigation by the Office or the Licensee itself and on which the Licensee is requested or has undertaken to place a hold on the disputed sum but disconnects the account prior to the Office's or its own ruling on the matter and there were no outstanding sums owed beyond the disputed sum.

2. Reconnection after Wrongful Disconnection

   The standard is defined as follows:

   A breach occurs where the Licensee, after erroneously disconnecting a supply, fails to reconnect same within FIVE (5) hours of being notified or having itself detected the error.

3. Changing Meters

   The standard is defined as follows:

   The Licensee must provide customers with details of the date of change, reason for change, meter readings on the day and serial number of the new meter on the day of the meter being changed within one (1) billing period of the change. This communication may be done via a method convenient to the customer and the Licensee.

4. Compensation

   Compensation for breaches of the Guaranteed Standards shall be as follows:

   4.1 General Compensation

   a. For residential customers, a breach of a standard will result in compensation equal to the reconnection fee. The reconnection fee shall be published on the website of the Licensee.

b. For commercial customers, the compensation will remain four (4) times the customer charge. The customer charge shall be published on the website of the Licensee.

c. Breaches will attract multiple payments up to eight (8) periods.

Compensation for Breach of Guaranteed Standards

CUSTOMER CLASS	COMPENSATION
Domestic: **Rate 10 – Residential Service**	$1,650.00
General Service: **Rate 20 – General Service**	$3,608.00
Power Service: **Rate 40 (all LV) – Power Service** **Rate 40A – Power Service** **Rate 50 (all MV) – large Power**	$25,420.00

4.2 Special Compensation

Wrongful Disconnection

a. Compensation for wrongful disconnection will be TWO (2) times the reconnection fee for residential customers and FIVE (5) times the customer charge for Commercial customers.

b. Reconnection after wrongful disconnection standard when breached will attract compensation of TWO (2) times the reconnection fee for residential customers and FIVE (5) times the customer charge for commercial customers.

4.3 Automatic Compensation

The Licensee will be required to automatically apply the necessary compensation to account for breaches in keeping with the schedule outlined in Table 1: Guaranteed Standards - Effective as of January 7, 2015:

Automatic Compensation will be applicable where there is a breach which is brought to the attention of the Licensee, as well as those breaches, which the Licensee itself recognizes. Automatic compensation becomes effective as of the Effective Dates indicated in Table 1, or as otherwise agreed between the Licensee and the Office. Customers will be required to submit claims prior to the Effective Date of the standard becoming automatic.

APPENDIX B

SCHEDULE 2 – OVERALL STANDARDS

OVERALL STANDARDS

CODE	STANDARD	UNITS	TARGETS JULY 2014 – MAY 2019
EOS1	No less than 48 hours prior notice of planned outages.	Percentage of planned outages for which at least forty-eight (48) hours advance notice is provided.	100 %
EOS2	Percentage of line faults repaired within a specified period of that fault being reported	Urban: 48 hours	100%
		Rural: 96 hours	100%
EOS3	System Average Interruption Frequency Index (SAIFI)	Frequency of interruptions in service	To be set annually
EOS4	System Average Interruption Duration Index (SAIDI)	Duration of interruptions in service	To be set annually
EOS5	Customer Average Interruption Duration Index (CAIDI)	Average time to restore service to average customers per sustained interruption.	To be set annually
EOS6	Frequency of meter reading	Percentage of meters read within time specified in the Licensee's billing cycle.	99%
EOS7 (a)	Frequency of meter testing	Percentage of rates 40 and 50 meters tested for accuracy annually	50%
EOS7 (b)	Frequency of meter testing	Percentage of other rate categories of customer meters tested for accuracy annually	7.5%
EOS8	Billing punctuality	98% of all bills to be mailed within a specified time after meter is read.	5 Working days
EOS9	Restoration of service after unplanned (forced) outages on the Distribution System	Percentage of customer's supplies to be restored within 24 hours of forced outages in both Rural and Urban areas.	98%

EOS10	Responsiveness of call Centre representatives	Percentage of calls answered within 20 seconds	90%
EOS11	Effectiveness of call Centre representatives	Percentage of complaints resolved at first point of contact	To be set
EOS12	Effectiveness of street lighting repairs	Percentage of all street lighting complaints resolved within 14 days	99%

Standards will not be in effect during periods of Force Majeure.

APPENDIX C

LIST OF REFERENCES

1. 2015 Electricity Act
2. OUR Act and 2015 Amendments
3. National Energy Policy (20% RE generation source for energy sector) and draft sub-sector policies
4. Licensee 2016 All-Island License (NB Conditions 2 (3), 13, 14, 16, 17 (including the Guaranteed Standards and the Overall Standards), 24(5), 25
5. OUR existing Generation Code
6. Licensee draft Transmission Code
7. Licensee draft Distribution Code
8. Licensee Standard Terms and Conditions of Service (approved by OUR) updated July 2008 and on JPS website, with a carve-out provided under Condition 14(1) of the Licence for special contracts and revisions in accordance with the mechanism under Condition 13(10)(ii)
9. Licensee Operating Policies and Procedures (confidential) (referenced in Grid Code)
10. Metering Licensee Licence: Conditions 2 (3), 13, 14, 16, 17(including the Guaranteed Standards and the Overall Standards), 24(5), 25
11. Licensee code of practice for local connection (connections within 100m of the Distribution Line)
12. Licensee code of practice for complex connections (connections outside 100m of the Distribution Line), including design and build
13. Licensee code of practice for temporary supply (i.e. construction, events etc.)
14. JPA Rate Schedule with classification of customers
15. Licensee Engineering Bulletin TSD 007/3 Apr 2008
16. Licensee Disconnection & Reconnection Policy Nov. 29, 2010
17. Licensee Line Extension Policy Document Updated July 1, 2008
18. OUR Metering Protocol on Administrative and Testing Procedure
19. Licensee Policy & Procedures – Customers with Special Needs Programme

20. Licensee Customer Service Code of Practice March 2013
21. OUR Revised Determination notice – Standard Offer Contract for the purchase of As Available Intermittent Energy from Renewable Energy Facilities up 100 kW, May 01, 2012.
22. Licensee Back Billing Policy