Registration No: KOD/ST/No.9/2025

Suruhanjaya Tenaga
Energy Commission

GRID CODE FOR PENINSULAR MALAYSIA
ADDITIONAL CODE

ADDITIONAL CODES

Registration Record

REGISTRATION NO.	REVISION DATE	REMARKS

ELECTRICITY SUPPLY ACT 1990
[*Act 447*]

GRID CODE FOR PENINSULAR MALAYSIA – ADDITIONAL CODES

KOD/ST/No.9/2025

IN exercise of the powers conferred by subsection 50A(2) of the Electricity Supply Act 1990 [*Act 447*], the Commission issues the following codes:

Citation and commencement

1. These Codes may be cited as the **Grid Code for Peninsular Malaysia – Additional Codes.**

2. These Codes come into operation on 01 January 2026.

Purpose

3. The purpose of the Additional Codes are to specify the technical procedures, requirements, responsibilities and obligations of the Grid System Operator, Single Buyer, Grid Owner and all Users of the Grid System to ensure its efficient development and secure operation without unduly discriminating any user or category of users.

Interpretation

4. In these Codes, unless the context otherwise requires, the definitions of terms used in these Codes are as provided in the Additional Code: Glossary and Definitions.

Date: 28 March 2025

SITI SAFINAH BINTI SALLEH
Chief Executive Officer
Energy Commission

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Glossary and Definitions (GD)

GD.1 General

GD.1.1 This part of the Additional Code provides the definitions of terms used in the Grid Code.

GD.2 Terms and Definitions

Term	Definition
AC	means alternating current.
AC Interconnection	means an AC connection between the Peninsular Malaysia Power System and a neighbouring power system.
Act	means the Electricity Supply Act 1990 [*Act 447*]
Active Energy	means the electrical energy produced, flowed, or supplied by an electric circuit during a time interval, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, i.e.: 1000 Wh = 1 kWh 1000 kWh = 1 MWh 1000 MWh = 1 GWh 1000 GWh = 1 TWh
Active Power	means the product of voltage and the in-phase component of alternating current measured in units of watts and standard multiples thereof, i.e.: 1000 Watts = 1 kW 1000 kW = 1 MW 1000 MW = 1 GW 1000 GW = 1 TW
Active Power Reserve	means the Active Power output held in reserve by part loading of a Generating Module equal to the difference between the full output capability and the part loaded output.

Term	Definition
Additional Generation	means the additional output obtainable from Power Station and Interconnection Transfers in excess of the setpoint issued from the Unit Schedule or from the Interconnection Transfer.
Aggregator	means a person acting on behalf of a group of Demand Response or Generating Units which together are capable of providing a service which is subject to Central Dispatch from the Grid System Operator.
Agreement	means any technical and/or commercial agreement signed between two or more parties in relation to the supply of electricity in Malaysia.
Ancillary Service	means a service, other than the generation of electricity, which is used to operate a stable and secure Grid System including Reactive Power, Operating Reserve, Frequency Control and Black Start Capability.
Annual Peak Demand Condition	means the highest electricity demand in megawatts (MW) recorded by the Grid System Operator or forecasted by the Single Buyer in any one (1) year under the prevailing system conditions.
Anti Islanding Protection	means a Protection disconnecting a Power Park Module (PPM) or an Energy Storage Unit, in case of an unwanted operation of this PPM or Energy Storge Unit, feeding a network disconnected from the Grid System.
Apparatus	means any electrical apparatus and includes the device or fitting in which a conductor is used, or of which it forms part of.
Apparent Power	means the product of voltage and current measured in units of voltamperes and standard multiples thereof, in an AC system i.e.: 1000 VA = 1 kVA 1000 kVA = 1 MVA
Area Manager	means a manager appointed by the Grid Owner whose management unit is a geographical area embracing part of the Grid System.

Term	Definition
Asset	means anything that has value to an entity, including business processes, information, hardware, software, networks and sites.
Associated User	means a User who does not own a Metering Installation but has fiscal and contractual interest in the test results or data flowing from the Metering Installation, and also includes a Consumer who has such an interest.
ATC	means Available Transmission Capacity, which refers to the remaining transmission capacity between two interconnected areas for further commercial activities above already committed activities of the transmission networks. The available Transfer Capacity is equal to: Net Transfer Capacity minus Notified Transmission Flow ATC = NTC - NTF
Authority for Access	means an authority issued by the owner of a site which grants the holder the right to unaccompanied access to sites containing exposed High Voltage (HV) conductors.
AGC	means an Automatic Generation Control, which refers to the equipment fitted to a Generating Module that automatically responds to signals from equipment at GSO Control Centre to adjust the output of selected Generating Module in response to a Frequency deviation and/or power flow on Interconnection usually for load following purposes.
AHVC	means an Automatic High Voltage Control, which refers to Voltage Control functionality provided by the plant which automatically regulates the voltage of the selected HV busbar/s of the generating facility substation based on corresponding signals from GSO.
APC	means an Automatic Power Curtailment, which refers to the capability of the PPM and the Energy Storage Unit to reduce their Active Power output upon the request of GSO Control Centre.

Term	Definition
Automatic Switching Equipment	means any switching equipment which carries out automatic switching of Plant, Apparatus and Equipment based upon a pre-arranged set of instructions, sequence and timing.
AVR	means an Automatic Voltage Regulator, which refers to the equipment fitted to a Generating Module that automatically responds to signals from equipment at GSO Control Centre to adjust the output of selected Generating Module in response to a voltage deviation.
Auxiliary Gas Turbine	means a Gas Turbine engine driving a Generating Unit which can supply a Unit Board or Station Board, which can start without an electrical power supply from outside the Power Station within which it is situated.
Auxiliary Diesel Engine	means a diesel engine driving a Generating Unit which can supply a Unit Board or Station Board, which can start without an electrical power supply from outside the Power Station within which it is situated.
Availability	means a measure (or the length) of time for which a Generating Module, transmission line, or any other system component or facility is capable of providing service when energised, irrespective of whether or not it is actually in service.
Availability Declaration	means a submission by each Generator, Energy Storage and Aggregator in respect of each of its Dispatch Units and by each Externally Interconnected Party in respect of its transfers, to the GSO and Single Buyer stating whether or not such Generating Module or Interconnection Transfer, as the case may be, is proposed by that Generator, Energy Storage and Aggregator to be available for generation in respect of the next following (or as the case may be, the existing Availability Declaration Period) Availability Declaration Period and, if so, the Offered Availability, in respect of any time period during such Availability Declaration Period.
Availability Declaration Period	means the period beginning at 00:00 and ending at 24:00 hours on the Schedule Day.

Term	Definition
Availability Notice	means a notice given by each Generator to the GSO and Single Buyer in relation to each Centrally Dispatched Generating Unit.
Monitoring Test	means a test to establish the compliance of a **Generating Module** with its **Declared Availability**.
Average Conditions	means the combination of weather elements within a period of time that is the average of the observed values of those weather elements during equivalent periods over many years.
Back-Up Protection	means the protection equipment or system which is intended to operate when a Grid System fault is not cleared in due time because of failure or inability of the Main Protection to operate or in case of failure to operate of a circuit-breaker other than the associated circuit breaker.
BESS	means the Battery Energy Storage System, which refers to an Equipment which consists of a set of batteries connected to the Grid System through a DC Converter. BESS have the capability to consume or supply electricity to the Grid System.
Billing	means a process involving gathering metering data, calculation of payments in accordance with the billing rules and ends with the issuance of invoice.
Billing Period	means the period of one (1) calendar month for fiscal settlement defined in the relevant agreement.
Billing System	means the assets of the Single Buyer, systems and procedures for the calculation in accordance with the billing rules of payments which become due thereunder, as modified from time to time.
Black Start	means the procedure necessary for a recovery from a **Total Blackout** or **Partial Blackout** of the **Grid System**. It is initiated by the **GSO** or by a party authorized by the **GSO** and progressed under the direction of the **GSO**.
Black Start Capability	means the ability of a **Power Station** equipped for **Black Start** capability, that is the capability to **Start – Up** at least one of its **Generating Units** from total **Shutdown** and to energise a part of the **Grid System** and to be synchronized to the **Grid System** upon

Term	Definition
	instruction from the **GSO**, within a set time period agreed with the **GSO**, without any external electrical power supply.
BSGU	means a **Black Start Generating Unit,** which refers to a **Generating Unit** capable of **Black Start.**
Black Start Generating Unit Test	means a **Black Start Test** carried out on a **Generating Unit**, at a **Black Start Power Station** while the **Black Start Power Station** remains unconnected to an external electrical supply.
Black Start Power Station	means a **Power Station** which is registered by the **Single Buyer** and the **GSO**, pursuant to the relevant **Agreement**, as having a **Black Start Capability**.
Black Start Power Station Test	means a **Black Start Test** carried out by a **Generator** with a **Black Start Power Station**, on the instructions of the **GSO**, in order to demonstrate that a **Black Start Power Station** has a **Black Start Capability** while the **Black Start Power Station** is disconnected from all external electrical supplies.
Black Start Test	means a test of the **Black Start Capability** of a **Generating Module** or a **Power Station** according to OC10.
Business Day	means Monday to Friday (excluding public holidays) on which banks are open for domestic business in the city of Kuala Lumpur.
Cancelled Start	means a response by a **Generator** to an instruction from the **GSO** cancelling a previous instruction to **Synchronize** to the **System** or come to **Hot Standby**, before **Synchronization** has been completed or **Hot Standby** reached.
Capacity	Means the power output or power carrying capacity or rating of **Generation**, **Transmission** and **Distribution Plant** or **Apparatus** or **Equipment**.
Capacity Allocation	means the amount in MW allocated on a half hourly basis for a day, by GSO for a cross-border exchange to a foreign company or a **User** of the Grid System of Malaysia.

Term	Definition
Caution Notice	means a written safety notice clearly visible to personnel affixed near an isolating device to warn of the state of the isolating device with respect to safety.
CCGT Module	means a **Combined Cycle Gas Turbine Module**, which refers to a collection of **Generating Units** (registered as a **CCGT Module** under the **PC**) comprising one or more **Gas Turbine Units** (or other gas based engine units) and one or more **Steam Units** where, in normal operation, the waste heat from the **Gas Turbines** is passed to the water/steam system of the associated **Steam Unit** or **Steam Units** and where the component **Units** within the **CCGT Module** are directly connected by steam or hot gas lines that enable those **Units** to contribute to the efficiency of the combined cycle operation of the **CCGT Module**.
CCGT Module Planning Matrix	means a matrix in the form set out in **OC2** showing the combination of **CCGT Units** within a **CCGT Module** that would be running in relation to any given MW output.
CCGT Unit	means a **Generating Unit** within a **CCGT Module**.
CDGU Two Shifting Limit	means the **Two Shifting Limit** of a **Centrally Dispatched Generating Unit**.
Central Dispatch	means the process of **Real-Time Scheduling** and issuing of direct operational instructions by the **GSO** to **Generating Modules, Energy Storage Units** and **Aggregators**.
CDGU	means **Centrally Dispatched Generating Unit**, which refers to a **Generating Unit or Module** that is centrally dispatched by the **GSO. CDGU applies to Aggregators.**
Chairperson	means the chairperson of the **Grid Code for Peninsular Malaysia Committee**.
Charge	means the process by which a **BESS** imports electrical energy from the **Grid System** and store the energy in its batteries.

Term	Definition
Check Meter	means a **Meter**, other than a **Main Meter**, used as a back-up source of **Metering Data** for certain types of **Metering Installations**.
Check Metering Data	means the **Data** recorded by and stored in a **Check Metering Installation**.
Check Metering Installation	means a **Metering Installation**, other than a **Main Metering Installation**, used as a back-up source of **Metering Data** for certain types of **Metering Installation**.
Circuit Breaker Fail Protection	means the protection system installed to automatically open other circuit breakers that can isolate a transmission circuit or equipment when the main circuit breaker installed for that purpose fails to operate correctly in response to a signal received from the associated **Main** or **Back-up Protection**.
Code	means a set of rules defining appropriate action, conduct and behaviour and in particular any one of the Chapters or Sections or clauses of this **Grid Code** mentioned in context.
Commissioning	means the activity undertaken by the **Grid Owner, User** or the **GSO** to prepare **Plant**, **Apparatus**, **Equipment** or **System** for connection to and operation within the **Grid System**.
Commissioning Test	means a test or a series of tests for establishing that, by measurement, the characteristics of **Plant** or **Apparatus** or **Equipment** are in accordance with the specified **Equipment** standards and its fitness for connection to and continuous operation on the **Grid System** without any adverse effects.
Committed Project Data	means the data relating to a **User Development** submitted by the **User** to the **Grid Owner,** and to the **Single Buyer** once the relevant **Agreement** for connection to the **Grid System** is signed.
Communication Protocol	means a protocol or procedure established to facilitate the exchange of relevant **Data** in a timely and orderly manner.
Completion Date	means the date when a **User** is expected to connect to or start using the **Grid System**.

Term	Definition
Complex	means a **Connection Site** together with the associated **Power Station** and/or **Network Operator** substation and/or associated **Plant** and/or **Apparatus**, as appropriate.
Compliance Test	means a test or a series of tests for establishing the compliance of a **Plant** or **Apparatus** or system with the relevant clauses of the **Grid Code** and any additional clauses in the relevant **Agreement**.
Connection	means the physical connection of **Plant**, **Apparatus** or **Equipment** or a **User System** to the **Grid System** or **User System**.
Connection Application	means the application made by a **User** to the **Grid Owner** and **GSO** for connection of **Plant**, **Apparatus** or **Equipment** or a **User System** to the **Grid System** or **User System**.
CC	means **Connection Code,** which refers to the **Part** of the **Grid Code** that is identified as the **Connection Code**.
Connection Point	means the agreed point of connection established between the **Grid System** or a **Network Operator's System** or the **User's System**, as the case may be, and the **User** seeking connection to any one of those systems.
Connection Site	means a **Grid Owner Site** or a **User Site**, as the case may be.
Constrained Schedule	means the **Unit Schedule** after all the **Transmission Constraints** are fully taken into account.
Consumer	means a person who is supplied with electricity or whose premises are connected for the purpose of being supplied with electricity by a supply authority or licensee.
Consumer Demand	means the electricity **Demand** of an individual, a group or all of the **Consumers** on the Peninsular Malaysian Power System.
Contracted Project Data	means the **Data** required to be submitted by the **User** in accordance with the **Planning Code** after completion and signing of the relevant **Agreement**.
SDC2	means the **Control, Scheduling and Dispatch**, which refers to that **Part** of the **Scheduling and Dispatch Codes** of this **Grid Code** that is identified as the **Control, Scheduling and Dispatch**.

Term	Definition
Control Calls	means a telephone call whose destination and/or origin is a key on the control desk telephone keyboard at the **GSO Control Centre** and that has the right to exercise priority over (i.e., disconnect) a call of a lower status.
Control Centre	means a location used for the purpose of control and operation of the **Grid System** or a **User System** other than a **Generator's System**.
Control Operation	means the continuous real time control activity undertaken for coordinated control of the **Grid System**.
Control Person	means the alternative term for **Safety Coordinator** only on the **Site Responsibility Schedule**.
Control Point	means the point from - *(a)* a **Grid Connected Customer's Plant** and **Apparatus** is controlled; *(b)* a **Demand Reduction Block** is co-ordinated**;** or *(c)* a **Power Station** is physically controlled by a **Generator**, as the case may be. For a **Generator** this will normally be at a **Power Station**.
Control Room	means the main room at a **Control Centre** where the **Control Engineer** undertake the control activities for operating the specific **Plant**, **Apparatus**, **Equipment**, **User System** or **Grid System**.
Control Telephony	means the method used by a **User's Responsible Engineer/Operator** and a **GSO Grid Operator** speak to one another for the purposes of control of the **Power System** in normal and emergency operating conditions.
Critical Assets	means the facilities, systems and equipment which, if destroyed, degraded or otherwise declared unavailable, would affect the reliability or operability of the Grid system.
Critical Incident	means an incident which may prejudice the safety or security of the **Grid System** and may potentially lead to widespread disruption of electricity supplies.

Term	Definition
CNII	means the **Critical National Information infrastructure,** which refers to those assets (real and virtual), systems and functions that are vital to the nation that their incapacity or destruction would have a devastating impact on: national economic strength; national image; national defense and security; government capabilities to function; and public health and safety. Energy is one of the CNII sectors.
Critical System	means the cyber assets essential to the reliable operation of critical asset. Critical System consists of those cyber assets that have at least one of the following characteristics: *(a)* the cyber asset uses a routable protocol to communicate outside the electronic security perimeter; *(b)* the cyber asset uses a routable protocol within a control centre; or *(c)* the cyber asset is dial-up accessible.
Customer	means a person to whom electrical power is provided (whether or not he is the same person as the person who provides the electrical power).
Customer Power Station	means the **Power Station** or **Generating Module** of a **Customer** to the extent that it operates the same exclusively to supply all or part of its own electricity requirements, and does not export electrical power to any part of the **Power System**.
Cyber Attack	means any attempt with malicious intent to gain access to network and information systems which may cause an incident where damages, disruptions or dysfunctionalities occur.
Cyber Resilience	means the ability to anticipate, withstand, adapt to and recover from adverse conditions, stresses, attacks, or compromises on systems that use or are enabled by cyber resources.
Cybersecurity	means the activities necessary to protect network and information systems, the users of such systems, and other persons affected by cyber threats.

Term	Definition
Cybersecurity Incident	means any real or suspected adverse cyber security event that violates, explicitly or implicitly, cybersecurity policy of GSO or the Users resulting in unauthorized access, denial of service or disruption, unauthorized use of computer resource for processing or storage of information or changes to data or information without authorization, leading to harm to the power grid or its critical subsectoral elements such as Generation, Transmission and Distribution.
Cybersecurity Policy	means documented set of business rules and processes for protecting information, computer resources, networks, devices, Industrial Control Systems and other OT resources.
Cybersecurity Procurement Requirements	means the requirements that entities define for new or updated ICT Equipment during procurement.
Cyber Threat	means any potential circumstance, event or action that could damage, disrupt or otherwise adversely impact network and information systems, the users of such systems and other persons.
Damping Ratio	means a term used to describe the rate at which the amplitude of a **Power System** oscillation frequency will decay after a disturbance.
Data	means any piece of information, parameter or sets of parameters in pursuance of enabling compliance with this **Grid Code**.
Data Collection System	means the data collection system for use in the calculation of payments due for electricity supplied or received.
Data Consistency Rules	means the rules relating to consistency of data submitted under the **SDCs**, to be applied by the **Single Buyer** under the **Grid Code** to data used in the software of the **Single Buyer** to prepare the **Unit Schedule**.
Data Entry Terminal	means a functional unit of a data station accommodated by each **User** at points agreed by the **User** and **GSO** for the purposes of information exchange with **GSO**.

Term	Definition
Data Logger	means a form of a data recorder which records and stores large amounts of measurement data at specific time intervals which can be locally and remotely interrogated.
DRC	means **Data Registration Code,** which refers to the **Part** of the **Grid Code** which is identified as the **Data Registration Code**.
Data Validity and Default Rules	means the rules relating to validity of data, and default data to be applied, in relation to data submitted under the **SDC's,** by the **Single Buyer** under the **Grid Code** to data used in the software of the **Single Buyer** to prepare the **Unit Schedule**.
DC	means direct current.
DC Converter	means any **User Apparatus** used to convert alternating current electricity to direct current electricity, or vice versa. A **DC Converter** is a standalone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion.
DC Network	means all items of **Plant and Apparatus** connected together on the direct current side of a **DC Converter**.
Declared Availability	means the availability of a **Generating Unit** or **Module** or **Interconnection Transfer** as proposed by a **Generator** or an **Externally Interconnected Party** in respect of the next **Availability Declaration Period**.
Defence Plan	means the organizational and technical measures, manual or automatic, to be undertaken to prevent the propagation or deterioration of a disturbance in the **Grid System**, in order to avoid being in an emergency state or blackout state
Demand	means the amount of electrical power consumed by the **Power System** comprising of both **Active** and **Reactive Power**, unless otherwise stated.

Term	Definition
Demand Control	means any methods of achieving a **Demand** reduction as set out in OC.4.
OC4	means **Demand Control,** which refers to the **Part** of the **Operating Codes** of this **Grid Code** which is identified as the **Demand Control**.
Demand Response	means the action resulting from management of the electricity **Demand** in response to supply conditions. **Aggregators** providing **Demand Response** are subject to **Central Dispatch**.
Demand Forecast	means **Demand Forecast,** which refers to the **Part** of the **Operating Codes** of this **Grid Code** which is identified as the **Demand Forecast (OC1)**.
Demand Reduction	means the reduction in **Demand** that must be implemented by each **User** upon the instruction received from the **GSO** under specific **Grid System** operational conditions.
Demand Reduction Block	means the size of the demand that can be reduced by a **User** upon instruction by the **GSO** or through equipment operated the **GSO Control Centre**.
Designed Minimum Operating Level	means the output (in whole MW) below which a **Dispatch Unit** has no **High Frequency Response** capability.
De-Synchronization	means the process of **De-Synchronizing** a **Generating Module**.
De-Synchronize	means the instruction issued by the **GSO** to a **Generator** for taking off a **Generating Module** off the **Grid System** or **User System**.
De-Synchronizing	The act of taking a **Generating Unit** or **Module** off the **Grid System** or **User System** to which it has been **Synchronized**, by opening any connecting circuit breaker and the term **De-Synchronizing** shall be construed accordingly.
Detailed Planning Data	means detailed additional data that the **Grid Owner** requires under the **PC** in support of **Standard Planning Data**. Generally, it is first supplied once a relevant **Agreement** is concluded.
Discharge	means the process when a **BESS** exports electrical energy to the **Grid System**

Term	Definition
Discrimination	means the quality where a relay or protective system is enabled to pick out and cause only the faulty **Apparatus** to be disconnected.
Dispatch	means the issue by the **GSO** of instructions for **Power Station** to achieve specific **Active Power** and/or **Reactive Power** or target voltage levels within the **Unit Scheduling and Dispatch Parameters** and by stated times.
Dispatch Parameters	has the same meaning as **Unit Schedule and Dispatch Parameters.**
Dispatch Unit	means a **Centrally Dispatched Generating Unit** or a **CCGT Module** or a **Power Park Module** or an **Energy Storage Unit** or an **Aggregator**, as the case may be.
Dispatch Instruction	means an oral or written instruction or electronic signal issued by the **GSO Control Centre** requiring a **Generating Module** or a **Power Station** or an **Energy Storage Unit** or an **Aggregator** to undertake a specific operational action at a specific time.
Dispatch Ramp Rate	means the rate at which a **Generating Module** is dispatched to increase or decrease its output by the **GSO Control Centre**.
Distribution Network	means the system consisting (wholly or mainly) of electric lines which are owned or operated by a **Distribution Licensee (Distributor)** and used for the distribution of electricity from **Grid Supply Points** or **Generating Modules** or other entry points to the point of delivery to **Customers** or other **Distributors**.
Distributor	means any licensee connected to the **Grid System** and distributes electricity for the purpose of enabling a supply to be given to any premises.
Earth Fault Factor	means 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 that would be obtained at the selected location without the fault.

Term	Definition
Earthing	means a way of providing a connection between conductors and earth by an **Earthing Device** as defined in OC8.4.1.2.
Electrical Equipment Standards	means Malaysian and international standards relating to electrical equipment prepared by reputable standards institutions such as MS, **IEC**, EN, DIN etc.
Electricity Industry	means any party associated with the generation, transmission, distribution and use of electrical energy and the institutions related to the governance thereof.
Electronic Security Perimeter	means the logical border surrounding a network to which the Cyber Systems of Power Supply System are connected using a routable protocol.
Embedded	means being a part of a **User System** but not directly connected to the **Grid System**.
Embedded Generating Module	means a **Generating Module** which is **Embedded** in a **User System**.
Embedded Power Station	means a **Power Station** which is **Embedded** in a **User System.**
Embedded Generating Unit	means a **Generating Unit** or a **Power Park Module** which is **Embedded** in a **User System**.
Emergency Instruction	means a **Dispatch** instruction issued by the **GSO,** pursuant to **SDC2**, to a **Dispatch Unit** which may require an action or response which is outside **Unit Scheduling and Dispatch Parameters, Generation Other Relevant Data** or **Notice to Synchronize.**
Energy (Active and Reactive)	Carrying the meaning **of Electrical Energy** see definitions of **Active** and **Reactive Energy**.
Commission	means the **Energy Commission** established under the Energy Commission Act 2001 [*Act 610*].
Energy Data	means any **Data** relating to the measurement of **Energy**.
Energy Measurement	means the measurement of **Active Energy** and **Reactive Energy.**

Term	Definition
Energy Requirements	means the annual requirements for electrical energy of Peninsular Malaysia.
Energy Storage Operator	means a person licensed by the **Commission** with an **Energy Storage Unit** directly connected to the **Grid System**
Energy Storage Unit	means any **Plant** and/or **Apparatus,** including **BESS** that is able to store energy by importing it from the **Grid** and to deliver energy by exporting it to the **Grid.**
Engineering Recommendation	means the documents referred to as such and issued by the former Electricity Council (prior to 1990) in UK and the present Energy Network Association.
Engineering Recommendation P28	means the "Engineering Recommendation P28, Issued by The Electricity Council of UK in 1989, entitled "Planning Limits for Voltage Fluctuation Caused by Industrial, Commercial and Domestic Equipment in the United Kingdom"".
Equipment	means any item for such purposes as generation, conversion, transmission, distribution or utilization of electrical energy, such as machines, transformers, **Apparatus**, measuring instruments, protective devices, wiring materials, accessories and appliances.
Estimated Registered Data	means the items of **Standard Planning Data** and **Detailed Planning Data** that either upon connection will become **Registered Data**, or, for the purposes of the **Plant** and/or **Apparatus** concerned as of the date of submission are **Registered Data**, but in each case for the ten (10) succeeding years will be an estimate of what is expected.
Event	means an unscheduled or unplanned occurrence on, or relating to, a **System** (including **Embedded Power Station**) including but not limited to that general description, faults, incidents and breakdowns and adverse weather conditions being experienced.
Excitation Loop	means the closed loop control portion of the **Excitation System** controlling the **Generating Unit** terminal **Voltage**.

Term	Definition
Excitation System	means the equipment providing the field current of a machine (**Generating Unit**), including all regulating and control elements, as well as field discharge or suppression equipment and protective devices.
Exciter	means the source of the electrical power providing the field current of a synchronous machine (**Generating Unit**).
Export	means the supply of **Power** or **Energy** into the **System** of an **Externally Interconnected Party**.
External Auditor	means a person appointed by the **Grid Code Committee** to conduct an external audit on the operations of the **GSO** and **Single Buyer**.
Externally Interconnected Party	means a person who operates an **External System** that is connected to the **Grid System** or a **Distribution Network** by an **External Interconnection**.
External Interconnection	means the **Apparatus** for the transmission of electricity to or from the **Grid System** or a **Distribution Network** into or out of an **External System**. For the avoidance of doubt, a single **External Interconnection** may comprise several circuits operating in parallel.
External System	in relation to the **Externally Interconnected Party,** means the **Grid System** or **Distribution Network** that it owns or operates that is located outside Peninsular Malaysia and any **Apparatus** or **Plant** that connects that system to the **External Interconnection** and that is owned or operated by such **Externally Interconnected Party**.
FFR	means **Fast Frequency Response**, which refers to the response by Power Park Modules or Energy Storage Unit to a deviation of the Grid System Frequency which is required for arresting frequency rise/decline, in order to improve the frequency peak/nadir and ROCOF.
Fast Load or Deload	means the capability to adjust active power output rapidly to preserve security of grid system in the event of system emergency.

Term	Definition
Fast-Start Capability	Means the ability of a **Dispatch Unit** to be **Synchronized** and **Loaded** up to full **Load** within five (5) minutes.
Fault Current Interruption Time	means the time interval from fault inception until the end of the break time of the circuit breaker (as declared by the manufacturer).
Fault Disconnection Facilities	in cases where no **Grid Owner,** circuit breaker is provided at the **User's** connection voltage, the facilities provided by the **User** to trip the **User's** circuit breakers and the higher voltage circuit breakers of the **Grid Owner** to isolate faults on the **User** system or the **Grid System**.
Final Report	means the report prepared by the **User** after satisfactory completion of **Compliance Tests** and submitted to the **Single Buyer, Grid Owner** and **GSO**.
Five Minute Reserve	means the component of the **Operating Reserve** that is fully available within five (5) minutes from the time of **Frequency** fall or a **Dispatch** instruction pursuant to **SDC2**, and which is sustainable for a period of four (4) hours.
FACTS	means **Flexible AC Transmission System**, which refers to family of power electronics based and other static controllers to enhance controllability and increase power transfer capability in electric power systems such as STATCOM (Static Synchronous Compensator) or Unified Power Flow Controller (UPFC).
Fluctuating Loads	means the **Loads** connected to the **Grid System** or **User System** exhibiting non-linear and/or randomly varying and/or special characteristics which may cause violation of the **Power Quality Standards** at the **Connection Point** and/or materially and adversely affect other **Users** or normal operation of **Plant**, **Apparatus** and **Equipment** connected to the **Grid System** or **User System** and may require installation of special measures or operational restrictions to mitigate or eliminate their adverse effects.
Forced Outage	means an **Unplanned** Outage as defined in **OC2**.

Term	Definition
Forecast Data	means the items of **Standard Planning Data** and **Detailed Planning Data** that will always be forecast.
Forecast Demand	means the forecast **Demand** of MW and MVAr of electricity (i.e., both **Active** and **Reactive Power**), by the **Grid Owner** aggregating the demand forecasts submitted by the **Users** and taking economic factors affecting electricity use into account.
Frequency	means the number of alternating current cycles per second (expressed in Hertz) at which a **System** is running.
SDC.3	means **Frequency and Interconnection Transfer Control**, which refers to that **Part** of the **Scheduling and Dispatch Code** of this **Grid Code** that is identified as the **Frequency and Interconnection Transfer Control**.
Frequency Sensitive Mode	means an operating mode which will result in **Active Power** output changing, in response to a change in **System Frequency**, in a direction that assists the recovery to **Target Frequency**, by operating so as to provide **Primary Response** and/or **Secondary Response** and/or **High Frequency Response.**
Gas Turbine Unit	means a **Generating Unit** driven by a gas turbine (for instance by an aeroengine) as its prime mover.
Gas Zone Diagram	means a single line diagram showing boundaries of, and interfaces between, gas insulated **HV Apparatus** modules which comprise part, or the whole, of a substation at a **Connection Site,** together with the associated stop valves and gas monitors required for the safe operation of the **Grid System** or the **User System**, as the case may be.
Generating Module	means a collection of one or more **Generating Units**, joined together by a **System** with a single electrical point of connection directly to the **Grid System**.
Generating Unit	Unless otherwise provided in the **Grid Code**, means any **Plant** and/or **Apparatus** that produces electricity.
Generation	means the **Power Stations** in Peninsular Malaysia.

Term	Definition
Generation Adequacy	means the adequacy of the **Generation Capacity** available to meet the peak power demand and overall annual energy demand in accordance with specific criteria providing an adequate margin as defined by the **Generation Reliability Standard**.
Generation Capacity	means the total installed **Power Station** capacity connected to the **Power System**.
Generation Development Plan	means the annual report submitted by the **Single Buyer** to the **Commission** calculating the generation capacity requirements for the next ten (10) years in accordance with the **Generation Reliability Standard**.
Generation Other Relevant Data	means the parameters listed in Appendix 2 of **OC2.**
Generation Planning Parameters	means the parameters listed in Appendix 2 of **OC2**.
Generation Reliability Standard	means The **Standard** which relates to provision of sufficient firm **Generation Capacity** to meet the **Demand** with a sufficient margin.
Generator	means a person who is Licenced by the **Commission** to generate electricity in Peninsular Malaysia.
Generator's Control Point	means the point from which the **Power Station** of a **Generator** is physically controlled.
Generator's Control Room	means the room used for the purpose of control and operation of a **Generator's Power Station**.
Generator's Power Station	means the **Power Station** owned, operated, and maintained by a specific **Generator**.
Generator Performance Chart	means a diagram which shows the MW and MVAr capability limits within which a **Generating Module** will be expected to operate under system steady state operational conditions.
Generator's System	means the **Connections**, **Plant**, **Apparatus** and **Equipment** in a **Power Station** owned, operated and maintained by a **Generator.**

Term	Definition
GD	means **Glossary and Definitions**, which refers to the **Part** of the **Grid Code** which is identified as the **Glossary and Definitions**.
Good Industry Practice	means the exercise of a degree of skill, diligence, prudence and foresight that would reasonably and ordinarily be expected from a skilled and experienced operator engaged in a similar field under the same or similar circumstances.
Government Agencies	means the agencies of the Government of Malaysia.
Grid Code	means a document that sets out the principles governing the relationship between the **GSO, Commission, Grid Owner, Single Buyer** and all **Users** of the **Grid System.**
GCC	means **Grid Code Committee**, which refers to the committee responsible for keeping the **Grid Code** under review in accordance with the rules and procedures defined under the **General Conditions** of this **Grid Code**.
Grid Code Dispute Resolution Procedure	means the procedure for resolution of **Grid Code** related disputes given in the **General Conditions** of this **Grid Code**.
Grid Code Effective Date	means the date at which the **Grid Code** becomes effective.
GCPM	means the **Grid Code for Peninsular Malaysia.** See **Grid Code.**
Grid Code for Peninsular Malaysia Committee	see **Grid Code Committee.**
Grid Connected Customer	means a **Customer** in Peninsular Malaysia, except for a **Network Operator** acting in its capacity as such and receiving electricity directly from the **Grid System**.
Grid Operator	means a person authorized to undertake **Grid System** control activity from the **GSO Control Centre**.
Grid Owner	means the party that owns the high voltage backbone **Grid System** and is responsible for maintaining adequate Grid capacity in

Term	Definition
	accordance with the provisions of the Grid Code and License Standards.
Grid Owner Site	means a **Site** owned or occupied pursuant to a lease, licence, or other agreement by the **Grid Owner** in which there is a **Connection Point**. For the avoidance of doubt, a site owned by a **User** but occupied by the **Grid Owner** as aforesaid, is a **Grid Owner Site**.
Grid Supply Point	means A point of supply from the **Grid System** to **Distributors**, **Network Operators** or **Grid Connected Customers**.
Grid System	means the system consisting (wholly or mainly) of high voltage electric lines (132kV and above) owned by the **Grid Owner** and used for the transmission of electricity from one **Power Station** to a sub-station or to another **Power Station** or between sub-stations or to or from any **External Interconnection**, and includes any **Plant** and **Apparatus** and meters owned by the **Grid Owner** and **Energy Storage Units,** which can be owned by the Grid Owner, in connection with the transmission of electricity.
Grid System Emergency	means any abnormal **System** condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the **Grid System**.
GSO	means **Grid System Operator**, which is the ring-fenced entity responsible for operational planning, real-time re-scheduling, dispatch and control of the **Grid System** in compliance with the provisions of the **Grid Code** and coordinates all parties connected to the **Grid System**.
GSO Control Centre	means the **Control Centre** from which the **GSO** directs the control of the Peninsular Malaysia Power System
GSO System Warning	means the **Warning** related to **Grid System** operation issued by the **GSO** to the **Users**.
High Frequency Response	means an automatic reduction in **Active Power** output of a **Generating Module** in response to an increase in **System**

Term	Definition
	Frequency above the **Target Frequency** (or such other level of **Frequency** as may have been agreed in a relevant **Agreement**). This reduction in **Active Power** output must be in accordance with the provisions of the relevant **Agreement** which will provide that it will be released increasingly with time over the period 0 to 10 seconds from the time of the **Frequency** increase on the basis set out in the relevant **Agreement** and fully achieved within ten (10) seconds of the time of the start of the **Frequency** increase and it must be sustained at no lesser reduction thereafter.
HV	means **High Voltage**, which refers to a **Voltage** normally exceeding 50 000 volts.
High Speed Delayed Auto Reclosing	means the process of automatic reclosure of circuit breakers clearing or isolating a fault quickly, after a specific time usually less than three (3) seconds, in the expectation that the fault is of transitory nature to affect rapid restoration of power flow.
House Load Operation	means the operation of a **Power Station** or a **Generating Unit** at a load level where only the demand of the **Power Station** or **Generating Unit** is being met.
HV Apparatus	means all **High Voltage (HV)** equipment in which electrical conductors are used, supported or of which they may form a part.
HVDC Interconnection	means an **Interconnection** employing **High Voltage Direct Current** conversion equipment at the sending and receiving end of the connecting transmission line which can provide bi-directional power flow from one power system to the other.
HV Generator Connection	means the **Plant** and **Apparatus** connected at the same voltage as that of the **Grid System** including **User's** circuits, the higher voltage windings of **User's** transformers and associated connection **Plant** and **Apparatus**.
Hydro Unit	means a **Generating Unit** where the prime movers and/or driving turbines are driven by water.
ICT Equipment	means an element or a group of elements of a communication network or information system.

Term	Definition
Import	means the supply of **Power** or **Energy** into the **Grid System** from an **Externally Interconnected Party**.
Inadequate System Margin	means a condition when the **GSO** determines that there is inadequate generation margin to meet **Demand**.
Incident	means any event, including a cybersecurity incident, compromising the availability, authenticity, integrity, or confidentiality of stored, transmitted or processed data or of the services offered by, or accessible via network and information systems.
IPP	means **Independent Power Producer**, which refers to a **Power Producer** having a **Power Purchase Agreement**.
ICT	means **Information and communication technology,** which refers to any information being processed digitally by information technology systems and transferred across communication networks.
ISD	means **Information Security Division,** which refers to a division accountable for cybersecurity.
ISO	means **Information Security Officer,** which refers to the designated employee having knowledge of information security and related issues, responsible for Cybersecurity.
Instructor Facilities	means an outstation instruction panel which gives at least sixteen (16) bits electronic signals with an audible alarm and acknowledge facilities to return message acknowledgement to the **GSO Control Centre**.
Interconnection	means the physical connection (consisting of **Plant** and **Apparatus**) connecting the **Grid System** to an **External System**.
Interconnection Agreement	means an agreement made between the **Single Buyer** and an **Externally Interconnected Party** relating to an **External Interconnection**.
Interconnected Parties	means the parties who are the signatories of an **Interconnection Agreement.**

Term	Definition
Intermittent Power Source	means the primary source of power for a **Generating Unit** that cannot be considered as controllable, e.g,. wind or solar.
IEC	means **International Electrotechnical Commission,** which refers to an international standards organization that prepares and publishes international standards for all electrical, electronic, and related technologies.
International Specification	means a commonly used **International** technical specification or a technical approval.
Interstart	means Fast-Start Capability that is initiated by external signal.
Intertrip Apparatus	means **Apparatus** which performs **Intertripping** of **Plant** and **Equipment**.
Intertripping	means the tripping of circuit-breaker(s) by commands initiated from **Protection** at a remote location independent of the state of the local **Protection**; or **Operational Intertripping**.
IP	means **Introduction and Purpose,** which refers to that **Part** of the **Grid Code** which is identified as the **Introduction and Purpose**.
Isolating Device	means a device for achieving **Isolation**.
Isolation	means the disconnection of **HV Apparatus** from the remainder of the **System** in which that **HV Apparatus** is situated as defined in OC8.4.1.2.
Joint System Incident	means an **Event** wherever occurring (other than on an **Embedded Power Station**) which, in the opinion of the **GSO** or a **User**, has or may have a serious and/or widespread effect, in the case of an **Event** on a **User(s) System(s)** (other than on an **Embedded Power Station**), on the **Grid System**, and in the case of an **Event** on the **Grid System**, on a **User(s) System(s)** (other than on an **Embedded Power Station**).
Key Safe	means a safe where a **Safety Key** is stored.
Key-Safe Key	means a key use to lock and unlock the **Key Safe** for implementation of the Safety Procedure in OC8.

Term	Definition
Largest Power Infeed Loss Risk	means the risk to the **Grid System** presented by the disconnection of the largest **Generating Unit** or transmission line or **Interconnection** carrying the largest amount of power in terms of resulting system **Frequency** deviation.
Least Cost Dispatch	means **Dispatch** of **Generation, Energy Storage Units and Aggregators** and **Demand Response** that results in **Least Cost Operation** of the **Grid System**, on the day, taking into account all factors specified in **SDC1**.
Least Cost Unit Schedule	means the schedule of **Generation, Energy Storage Units, Aggregators** and **Demand Response** prepared for the following day that, at the time of preparation, would result in **Least Cost Operation** of the **Grid System**, taking into account all factors specified in **SDC1**, if **Dispatched** the following day.
Least Cost Operation	means the Operation of the **Grid System** at minimum cost, taking into account all factors included in **SDC1** and any other factors (for example constraint costs) that may influence these costs.
Licence	means any licence granted to any **User** under the **Act**.
Licence Standards	means the standards relating to the reliability, security and quality of electricity supply prepared by the Licensee pursuant to the Licence approved by the **Commission**.
Live Apparatus Working	means the Maintenance or refurbishment of energized **Transmission Plant** or **Apparatus** undertaken by the **Grid Owner**.
Load	means the **Active**, **Reactive**, or **Apparent Power**, as the context requires, generated, transmitted, or distributed.
Load Shedding	means the Disconnection of **Load** from the **Grid System** for the purpose of **Demand Control**.
Loaded	means the state of a **Generating Module** when supplying electrical power to the **Grid System** or a **User System**.
Loading	means the output level of a **Generating Module** supplying electrical power to the **Grid System** or a **User System**.

Term	Definition
Load Following Capability	means the capability of a **Generating Module** to increase or decrease its output in a proportional manner to the increase in **Grid System Demand** in real time via **Automatic Generation Control (AGC)** and any other methods as specified in the Connection Code.
Local Safety Instructions	means the instructions on each **User Site** and **Grid Owner Site**, approved by Manager of the relevant **User** or **Grid Owner**, setting out the methods of achieving the objectives of **User's** or **Grid Owner's Safety Rules**, as the case may be, to ensure the safety of personnel carrying out work or testing on **Plant** and/or **Apparatus** on which his **Safety Rules** apply and, in the case of a **User**, any other document on a **User Site** containing rules regarding maintaining or securing the isolating position of an **Isolating Device**, maintaining a physical separation or maintaining, securing the position of an **Earthing Device**.
Location	means any place at which **Safety Precautions** are to be applied.
Locked	means a condition of **HV Apparatus** that cannot be altered without the operation of a locking device.
Long Term Flicker Severity	means a value derived from twelve (12) successive measurements of **Short-Term Flicker Severity** (over a two-hour period) and a calculation of the cube root of the mean sum of the cubes of twelve (12) individual measurements, as further set out in Engineering Recommendation P28.
Loss of Excitation Protection	means a term referring to the protection system installed for detecting the loss of excitation supply to a **Generating Unit** and disconnecting the **Generating Unit** from the **Grid System** or a **User System** upon detection of such a condition.
LOLP	means **Loss of Load Probability,** which refers to a reliability index that indicates the probability that some portion of the peak demand will not be satisfied by the available generating capacity as per **License Standard**. It may also be expressed as an expected duration in a year when the peak demand is not being met, in which case it is referred as Loss of Load Expectation (LOLE).

Term	Definition
Low Frequency Relay	has the same meaning as **Under Frequency Relay**.
Main Meter	means the main constituent part present in each **Metering Installation**, which provides **Metering Data** for **Settlement** purposes.
Main Metering Installation	means the installation containing the **Main Meter**.
Main Protection	means the **Protection** equipment or system expected to have priority in initiating either a fault clearance or an action to terminate an abnormal condition in a power system.
Main Range	means the mountain range spanning the Peninsular Malaysia.
Malaysian Electricity Supply Industry	means all parties involved in the electricity sector in Malaysia and the overall organization of this sector.
Malaysian Specification	means a commonly used Malaysian technical specification or a technical approval.
Malaysian Standard Time	means the reference time standard for **Malaysia**.
Manager	means a manager who has been duly authorized to sign **Site Responsibility Schedules** on behalf of the **User**.
Max Gen	means **Maximum Generation,** which refers to the maximum capacity of the Power Station up to the **Declared Availability**.
Meter	means a device for measuring and recording produced or consumed units of **Active Energy** and **Reactive Energy** and/or **Active Power** and/or **Reactive Power** and/or **Demand**.
Metering	means the process of measuring and recording the production or consumption of electrical energy.
MC	means **Metering Code,** which refers to that **Part** of the **Grid Code** which is identified as the **Metering Code (MC)**.

Term	Definition
Metering Data	means the metering data obtained from a **Metering Installation**, and/or processed data or substituted data that is used for **Settlement** purposes.
Metering Database	means a database that contains the **Metering Register** and the **Metering Data**.
Metering Installation	means a **Meter** and the associated current transformers, voltage transformers, metering protection equipment including alarms, LV electrical circuitry and associated data collectors, related to the measurement of **Active Energy** and/or **Reactive Energy** and/or **Active Power** and/or **Reactive Power,** as the case may be.
Metering Installation Outage	means the unavailability of a **Metering Installation** due to breakdown or testing or maintenance.
Metering Point	means the physical point at which electricity is metered.
Metering Register	means a register of information associated with a **Metering Installation**. This includes type and **Technical Specifications** of equipment, audit and calibration data, site specific data, etc.
Minimum Generation	means the minimum output of a **Power Station** under which it can stably operate.
Minister	means the Minister for the time being charged with the responsibility for matters relating to the supply of electricity.
Modification	means any actual or proposed replacement, renovation, modification, alteration or construction by or on behalf of a **User** to that **User's Plant** or **Apparatus** or the manner of its operation which has or may have a material effect on **Grid System** or a **User System**, as the case may be, at a particular **Connection Site**.
Multiple Point of Connection	means two or more **Points of Connection** interconnected to each other through the **Grid System**.
NACSA	means **National Cyber Security Agency,** which refers to the national lead agency for cybersecurity matters, with the objectives of securing and strengthening Malaysia's resilience in facing the

Term	Definition
	threats of cyber-attacks, by coordinating and consolidating the nation's best experts and resources in the field of cybersecurity.
NTC	means **Net Transfer Capacity,** which refers to the expected maximum volume of generation that can be wheeled through the interface between two systems, which does not lead to network constraints in either system, respecting some technical uncertainties on future network conditions
Network	means a general expression for a **Grid**, **Distribution**, **User,** or a **Network Operator's System**.
Network Data	means the data to be provided by the **Grid Owner** and **GSO** to **Users** or by the **Users** to the **Grid Owner** and **GSO** as the case may be.
Network Operator	means a person with a **User System** directly connected to the **Grid System** to which **Customers** and/or **Power Stations** (not forming part of the **Grid System**) are connected, acting in its capacity as an operator of the **User System**, but shall not include a person acting in the capacity of an **Externally Interconnected Party**, nor of a **Distributor**.
Network Operator's System	Any system owned or operated by a **Network Operator** comprising— *(a)* **Generating Module**s; *(b)* Systems consisting (wholly or mainly) of electric lines used for the **Distribution** of electricity from **Grid Supply Points** or **Generating Modules** or other entry points to the point of delivery to **Customers**, or other **Users**; and/or *(c)* Plant and/or Apparatus connecting the system as described above to the **Grid System** or to the relevant other **User System**, as the case may be.
Nominated Fuel	means the main fuel of a **Power Station** nominated by the **Grid Owner** based upon the calculations made in preparing the **Generation Development Plan**.

Term	Definition
Non-Spinning Reserve	means the reserve that is not spinning but available to start within its starting parameters.
Non-Working Day	means any day that is not a **Working Day**.
Normal CCGT Module	means a **CCGT Module** other than a **Range CCGT Module**.
Normal Operating Condition	means the operating condition of the **Grid System** when the voltage and frequency at all points on the system are within their normal limits and the system is secure against outages within **Transmission System Reliability Standards**.
Notice to Synchronize	means the period of time normally required to **Synchronize** a **Dispatch Unit** following instruction from the GSO as stipulated in relevant **Agreement**.
Novel Unit	means a tidal, wave, wind, geothermal, biomass or any similar, **Generating Unit**.
NTF	means Notified Transmission Flows, which refers to the part of the Net Transfer Capacity, which is used by the already accepted transfer contracts at the studied time frame.
OC.9	means **Numbering and Nomenclature,** which refers to that **Part** of the **Operating Codes** of this **Grid Code** that is identified as the **Numbering and Nomenclature**.
On-Line Fuel Changeover	means the fuel changeover functional requirements of a dual fuel or main and standby fuel **Power Station** specified by the **GSO and Single Buyer**.
OCs	means **Operating Codes,** which refers to that **Part** of the **Grid Code** that is identified as the **Operating Codes**.
OC1	means **Operating Code No 1 – Demand Forecast,** which refers to the **Operating Code No 1** of this **Grid Code,** dealing with **Demand** forecasting.
OC2	means **Operating Code No 2 - Outage and Other Related Planning,** which refers to the **Operating Code No 2** of this **Grid**

Term	Definition
	Code, dealing with operational planning and outage coordination matters.
OC3	means **Operating Code No 3** - **Operating Reserves and Response,** which refers to the **Operating Code No 3** of this **Grid Code,** dealing with operating reserve and its response for dealing with generation contingencies in operational timescales.
OC4	means **Operating Code No 4** - **Demand Control,** which refers to the **Operating Code No 4** of this **Grid Code,** dealing with the various forms of **Demand Control** methods available to the **GSO** in operating the system and their implementation.
OC5	means **Operating Code No 5** - **Operational Liaison,** which refers to the **Operating Code No 5** of this **Grid Code,** dealing with the procedures for communication and liaison between the **GSO** and the **Users** and their implementation.
(OC6)	means **Operating Code No 6** – S**ignificant Incident Reporting,** which refers to the **Operating Code No 6** of this **Grid Code,** dealing with the reporting of scheduled and planned actions and significant unscheduled occurrences such as faults and investigation of the impact of such occurrences.
OC7	means **Operating Code No 7 – Emergency Operations**, which refers to the **Operating Code No 7** of this **Grid Code,** dealing with the actions to be taken by the **GSO** in preparing operational strategies towards maintaining the integrity of the system under severe system contingencies beyond the security criteria, and implementation of those strategies.
OC8	means **Operating Code No 8** - **Safety Coordination**, which refers to the **Operating Code No 8** of this **Grid Code,** dealing with the co-ordination between **GSO** and **User**, in the establishment and maintenance of **Isolation** and **Earthing** so that work and/or testing can be carried out safely at **Connection Point.**
OC9	means **Operating Code No 9 - Numbering and Nomenclature**, which refers to the **Operating Code No 9** of this **Grid Code,**

Term	Definition
	dealing with the procedures for numbering and nomenclature of **HV Apparatus** at certain sites where new construction is to be integrated or changes are to be made to existing **Connection Point**.
OC10	means **Operating Code No 10 – Periodic Testing and Supervising**, which refers to the **Operating Code No 10** of this **Grid Code,** dealing with the procedures for periodic testing and supervising of the effects of a **User's System** on the **Grid System** and vice versa.
OC11	means **Operating Code No 11 - System Tests**, which refers to the **Operating Code No 11** of this **Grid Code,** dealing with the procedures for the establishment of system tests where commissioning and testing of equipment and its capability may require application of unusual or irregular operating conditions.
Operating Reserve	means the additional output from the **Generating Module** or the reduction in **Demand**, which must be realisable in real-time operation to respond in order to contribute to containing and correcting any **System Frequency** fall to an acceptable level in the event of a loss of generation or a loss of import from an **External Interconnection** or mismatch between generation and **Demand**.
Operation Diagram	means the Diagram which is a schematic representation of the **HV Apparatus** and the connections to all external circuits at a **Connection Site**, incorporating its numbering, nomenclature and labelling.
Operational Control Phase	means the **Operational Control Phase** follows on from the **Programming Phase** and covers the period down to real time.
Operational Effect	means any effect on the operation of the relevant **System** which will or may cause the **Grid System** or other **User System** to operate (or be at a materially increased risk of operating) differently to the way in which they would or may have normally operated in the absence of that effect.

Term	Definition
Operational Intertripping	means the automatic tripping of circuit-breakers to prevent abnormal system conditions occurring, such as over voltage, overload, **System** instability, etc. after the tripping of other circuit-breakers following power **System** disturbance(s) which includes **System** to **Generating Modules** or **System** to **Demand Intertripping** schemes or by **Special Protection** schemes.
Operational metering	means the measurements acquired using parts of a Metering installation (mainly CT+VT) in order to operate the Grid System in real-time.
Operational Planning	means the Planning through various timescales the matching of generation output with forecast **Demand** together with a reserve of generation to provide a margin, taking into account outages of certain **Generating Modules**, of parts of the **Grid System** and of parts of **User System** to which **Power Stations** and/or **Customers** are connected, carried out to achieve, so far as possible, the License Standards.
Operational Planning Phase	**Operational Planning Phase** covers several timeframes of operation from 5-year ahead to the start of the **Programming Phase**.
Operational Procedure	means the Procedure followed during real time operation of the **Grid System** included in that **Part** of the **Grid Code** which is identified as the **Operating Codes**.
Operational Metering	**Operational Metering** comprises **Installations** installed to measure voltage, current, frequency, **Active** and **Reactive Power**, and accept signals relating to plant status indications and alarms monitoring the circuits connecting the **User Plant** and **Apparatus** to the **Grid System** for operational purposes.
Operational Metering Data	means the data from **Operational Metering** collected by the **Remote Terminal Units** and used by the **GSO** in directing the coordinated operation of the **Grid System**.
OT Network	means **Operational Technology Network,** which refers to the communication and control systems that are used to monitor and

Term	Definition
	control the electricity transmission system by users. OT Network covers usually telecontrol in a broad sense (processing systems, including back-up, underlying networks, safety telephone) and electrical control, for the part of it that is composed of computer systems (mainly control command and metering systems).
Orange Warning	means a **System Warning** issued by the **GSO** that is related to the system operating conditions when there may be a high risk of **Demand Control**.
Outage Plan	means a plan prepared by the **GSO** that describes the planned **Generation** and/or **Transmission** outages for the different **Operational Planning** timescales.
Output Usable	means the portion of **Registered Capacity** which is not unavailable due to a **Planned Outage** or breakdown. For a **Power Park Module**, **Output Usable** also depends upon the **Intermittent Power Source** being at a level which would enable the **Power Park Module** to generate at **Registered Capacity**.
Outstation Interface Equipment	means the telecontrol equipment for data collection and data exchange with **GSO Control Cente**r, such as RTU, Gateway and control center master system.
Part Load	means the condition of a **Dispatch Unit** which is **Loaded** but is not running at its full **Availability**.
Partial Blackout	means a **Grid System** operational condition where after a disturbance all **Generation** has ceased in a part of the **Grid System** and there is no electricity supply from **External Interconnections** or other parts of the **Grid System** to that part of the **Grid System**, with the result that it is not possible for that part of the **Grid System** to begin to function again without the **Grid System Operator**'s directions, including provisions relating to a **Black Start**.
Part *(of the Grid Code)*	means individual self-contained chapters or sections of the **Grid Code** addressing specific subject areas.

Term	Definition
Peak Demand Conditions	means the **Grid** or **Power System** conditions pertaining to the peak **System Demand**.
Peninsular Malaysia Maximum Demand	means the peak MW demand of the day for the year for the total Peninsular Malaysian Grid System.
Peninsular Malaysia Minimum Demand	means the minimum MW demand of the day for the year for the total Peninsular Malaysian Grid System.
Phase Unbalance	means the difference in the magnitude of the three individual phase voltages due to the imbalance in the magnitude of the **Demand (Load)** connected to each one (1) of the three (3) phases.
PMU	means **Phasor Measurement Unit,** which refers to the sensor that measures bus voltage angles and frequencies at high sampling rate.
Planned Outage	means an outage of **Power Station** or of part of the **Grid System**, or of part of a **User System**, co-coordinated by **GSO** under **OC2**.
Planning Data	means the data associated with the long-term **Planning** of the **Grid System** and for calculation of **Generation Adequacy** to meet the **Forecast Demand**.
PC	means **Planning Code,** which refers to that **Part** of the **Grid Code** which is identified as the **Planning Code (PC)**.
Plant	means fixed and movable items used in the generation and/or supply and/or transmission of electricity, other than **Equipment**.
Point of Common Coupling	means the point on the **Grid System** which is electrically closest to the **User** installation at which either **Demands** (**Loads)** are, or may be, connected.
Point of Connection	means an electrical point of connection between the **Grid System** and a **User's System**.
Pole-Slipping Protection	means the protection system installed for detecting a specific **Generating Unit** operational condition termed "pole slipping" and disconnecting the **Generating Unit** from the **Grid System** or a **User System** upon detection of such a condition. This disconnection being implemented to prevent a **Power System**

Term	Definition
	Blackout due to the high risk of consequential adverse cascade tripping of transmission circuits by their protection at times when such **Generating Unit** operation is permitted to persist.
Power Electronic Device	means the **Plant** for installation on the **Grid System** which utilise various types of power electronic devices.
Power Factor	means the ratio of **Active Power** to **Apparent Power**.
Power Island	means **Dispatch Units** at an isolated **Power Station**, together with its local **Demand**.
PPA	means **Power Purchase Agreement**, which refers to **Agreement** between the **Single Buyer** and a **Generator** or **Network Operator** relating to the financial and technical conditions relating to the purchase of the **Power Station** output and technical conditions relating to its connection to and performance on the **Grid System**.
PPM	means **Power Park Module,** which refers to a collection of one or more non-synchronous **Generating Units** (registered as a **Power Park Module** under the **PC**) that are powered by an **Intermittent Power Source**, joined together by a **System** with a single electrical point of connection directly to the **Grid System**. The connection to the **Grid System** may include a **DC Converter**.
Power Park Unit	means an individual **Generating Unit** within a **Power Park Module.**
Power Station	means an installation comprising one or more **Generating Modules** (even where sited separately) owned and/or controlled by the same **Generator**, which may reasonably be considered as being managed as one **Power Station**.
Power Station Auxiliaries	means the auxiliary **Plant** enabling normal functioning of a **Power Station**.
Power System	means the **Grid System** and all **User System** within Peninsular Malaysia.
PSS	means **Power System Stabiliser,** which refers to equipment controlling the **Exciter** output via the voltage regulator in such a

Term	Definition
	way that power oscillations of the synchronous machines **(Generating Units)** are dampened. Input variables may be speed, frequency or power or a combination of these system quantities.
Preliminary Project Data	means the Data relating to a proposed **User Development** at the time the **User** applies to the **Grid Owner** for connection to the **Grid System**.
Primary Response	means the automatic Active Power response. To provide such a response, to a deviation of the Grid System **Frequency** which requires changes in the generator unit output to arrest the fall or rise of **Frequency** The quantum of response shall be fully realisable within ten (10) seconds from the time of frequency change and fully sustainable for a at least a further twenty (20) seconds.
Programming Phase	means the period between **Operational Planning Phase** and the **Operational Control Phase**. It starts at the eight (8) weeks ahead stage and ends with the issue of the **Unit Schedule** for the day ahead.
Protection	means the provisions for detecting abnormal conditions on a **System** and initiating fault clearance or actuating signals or indications.
Protection Apparatus	means a group of one or more **Protection** relays and/or logic elements designated to perform a specified **Protection** function.
Protection of Interconnecting Connections	means the requirements for the provision of **Protection** equipment for interconnecting connections specified by the **Single Buyer** in consultation with the **Grid Owner** and the **GSO**. The term “interconnecting connections” means the primary conductors from the current transformer accommodation on the circuit side of the circuit breaker to the **Connection Point**.
Prudent Industry Practice	means the exercise of that degree of skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from

Term	Definition
	a skilled and experienced operator engaged in the same type of undertaking under the same or similar circumstances.
Pumped Storage Generator	means a **Generator** which owns and/or operates any **Pumped Storage Plant.**
Range CCGT Module	means a **CCGT Module** where there is a physical connection by way of a steam or hot gas main between that **CCGT Module** and another **CCGT Module** or other **CCGT Modules**, which connection contributes (if open) to efficient modular operation, and which physical connection can be varied by the operator.
Rated Insulation Levels	means the Rated Insulation Levels to which all the insulation on the Grid System is designed, procured, installed, operated and maintained.
Rated MVA	means the “rating-plate” MVA output of a **Generating Unit,** being that output up to which the **Generating Unit** was designed to operate (Calculated as specified in **British Standard BS** EN 60034 – 1: 1995). For **Power Park Module**, **Rated MVA** refers to the nominal rating for the MVA output being the maximum continuous electric apparent power output which the **Power Park Module** was designed to achieve under normal operating conditions
Rated MW	means the “rating-plate” MW output of a **Generating Unit,** being that output up to which the **Generating Unit** was designed to operate (Calculated as specified in **British Standard BS** EN 60034 – 1: 1995). For **Power Park Module**, **Rated MW** refers to the nominal rating for the MW output being the maximum continuous electric output power which the **Power Park Module** was designed to achieve under normal operating conditions.
Reactive Compensation Equipment	means any shunt-connected equipment connected to the **Grid System** or a **User System** which is switched and/or controlled such that it generates or absorbs reactive power to the **Grid System** at the busbar at which it is connected so as to enable the **GSO** to control and stabilise the system voltage at that busbar.
Reactive Energy	means the electrical energy produced, flowing or supplied by an electric circuit during a time interval, being the integral with

Term	Definition
	respect to time of the instantaneous reactive power, measured in units of var-hours or standard multiples thereof, i.e.: 1000 VArh = 1 kVArh 1000 kVArh = 1 MVArh 1000 MVArh = 1 GVArh 1000 GVArh = 1 TVArh
Reactive Power	means the product of voltage and current and the sine of the phase angle between them measured in units of voltamperes reactive and standard multiples thereof, i.e.: 1000 VAr = 1 kVAr 1000 kVAr = 1 MVAr
Red Warning	means a **System Warning** issued by the **GSO** related to the system operating conditions when there may be a **Demand Control** imminent.
Registered Capacity	In the case of a **Generating Unit** being something other than that forming part of a **CCGT Module**, means the normal full load capacity of a **Generating Unit** as declared by the **Generator**, less the MW consumed by the **Generating Unit** through the **Generating Unit's** unit transformer when producing the same (the resultant figure being expressed in whole MW.) In the case of a **CCGT Module**, means the normal full load capacity of a **CCGT Module** as declared by the **Generator**, being the **Active Power** declared by the **Generator** as being deliverable by the **CCGT Module** at the **Connection Point** (or in the case of an **Embedded CCGT Module**, at the **User System Entry Point**), expressed in whole MW. In the case of a **Power Park Module**, **Registered Capacity** means the normal full load capacity of the **Power Park Module** as declared by the **Generator**, being the **Active Power** declared by

Term	Definition
	the **Generato**r. The **Active Power** is declared by the **Generator** as being deliverable by the **Power Park Module** at the **Connection Point**, expressed in whole MW. In the case of an **Energy Storage Unit**, **Registered Capacity** means the normal full load capacity of the **Energy Storage Unit** as declared by the **Energy Storage Operator**, being the **Active Power** declared by the **Energy Storage Operator**. The **Active Power** is declared by the **Energy Storage Operator** as being deliverable by the **Energy Storage Unit** at the **Connection Point**, expressed in whole MW.
Registered Data	means the items of **Standard Planning Data** and **Detailed Planning Data** which upon connection become fixed (subject to any subsequent changes).
Regulations	means the 1994 Electricity Supply Regulations 1994 [*P.U.(A) 38/1994*].
RTU	means **Remote Terminal Unit,** which refers to a unit installed at a **Connection Point** or **Metering Point** that communicates all the **Operational Metering** Data and the **Revenue Metering Data** to a central data collection system for the operational use of the **GSO**.
Relay Setting	means the values of parameters defining the appropriate operation of a **Protective Relay** within a **Protection** system.
Responsible Manager	means the **Manager** who have been duly authorized to sign **Site Responsibility Schedules** on behalf of the **User**.
Responsible Person	means a person nominated by a **User** to be responsible for control and operation of their associated **Plant** and **Apparatus**.
Restoration Plan	means a coordinated plan of actions to be carried out to safely and effectively restore the **Grid System** back to a normal operating state following the occurrence of a **Blackout**.
Retailer	The Retailer is a User of the Grid System, who is allowed by the law to sell electricity to other Users. Retailer can have its own facilities for generating electricity or buy electricity in bulk and sell

Term	Definition
	it to others. In that case, Retailer may have its own assets connected to the grid, by example Grid Connected Customer. Or he can be virtual, which means without any assets connected to the grid, operating only for buying and selling electricity. The Retailer must have a licence from the Energy Commission for carrying out his activities.
Revenue Metering	means a **Metering Installation** at a **Connection Point** or a **Generator Circuit**, for fiscal accounting, contractual and/or statistical purposes.
Revenue Metering Data	means the data recorded and stored in the **Revenue Metering Installations**.
Revenue Metering Installation	means a **Metering Installation** dedicated to providing data for **Billing** purposes.
RISP	means an acronym for a Record of Interconnection of Safety Precautions as seen in **OC8**.
OC8	means **Safety Coordination,** which refers to that **Part** of the **Operating Codes** of this **Grid Code** which is identified as the **Safety Co-ordination**.
Safety Coordinator	means a person nominated by the **Grid Owner** and each **User** to be responsible for the co-ordination of **Safety Precautions** at each **Connection Point** when work (which includes testing) is to be carried out on a **HV Apparatus** that necessitates the provision of **Safety Precautions** from another **System**.
Safety Key	means a key used to lock and unlock the switching operation of an isolating device for the implementation of safety precaution in OC8.
Safety Precautions	means the Isolation and/or **Earthing** of **HV Apparatus**.
Safety Rules	means the rules of the **Grid Owner** or a **User** that seek to ensure that persons working on **Plant** and/or **Apparatus** to which the rules apply are safeguarded from hazards arising from the **System**.

Term	Definition
SCADA	means an acronym for Supervisory Control and Data Acquisition, the real time computer system that is used to monitor and control the **Power System** in real time.
Schedule Day	means the period from 00:00 to 24:00 hours in each day as defined in **SDC1**.
Scheduling	means the process of compiling and issuing a **Unit Schedule**, as set out in **SDC1** and the process which identifies the amount and types of generating sources which may be required to meet the forecast demand in any particular time interval in the next Schedule Day with the appropriate level of security whilst maintaining the integrity of the **Grid System**.
SDCs	means **Scheduling and Dispatch Codes,** which refers to that **Part** of the **Grid Code** that specifies the **Scheduling and Dispatch** process.
SDC1	means **Scheduling and Dispatch Code No 1** - **Unit Scheduling,** which refers to the **Scheduling and Dispatch Code No 1** of this **Grid Code** dealing with the procedures based upon the prices quoted in **Power Purchase Agreements (PPAs)** and certain other technical performance and outage information, the preparation of an indicative **Least Cost Unit Schedule** indicating which **Generating Modules, Energy Storage Units and Aggregators** may be instructed or **Dispatched** the following day.
SDC2	means **Scheduling and Dispatch Code No 2** - **Control, Scheduling and Dispatch,** which refers to the **Scheduling and Dispatch Code No 2** of this **Grid Code** dealing with issuing **Control**, **Scheduling and Dispatch** instructions to **Generating Modules**, **Energy Storage Units, Aggregators** and the receipt and issue of certain other associated information.
SDC3	means **Scheduling and Dispatch Code No 3** - **Frequency and Interconnection Transfer Control,** which refers to the **Scheduling and Dispatch Code No 3** of this **Grid Code** dealing with the procedures and requirements in relation to control of system **Frequency** and Interconnection power transfers.

Term	Definition
SDP Notice	means **Scheduling and Dispatch Parameter Notice,** which refers to a notice given by a **Generator,** an **Energy Storage Operator** or **Aggregator** to the **GSO and Single Buyer** detailing changes to the **Scheduling and Dispatch Parameters** of any of its **Dispatch Unit** in respect of the following **Schedule Day**.
Secondary Response	means the automatic or manual **Active Power** response by a **Unit** to a deviation of the **Grid System Frequency** which is fully realisable within thirty (30) seconds from the time of **Frequency** change to take over from the **Primary Response** and fully sustainable for at least thirty (30) minutes from **Units** dispatched by the **GSO** to provide such a response. .
Secretary	means the Secretary of the **Grid Code for Peninsular Malaysia Committee**.
Settlement	means the process and procedure for the calculation of payments that become due under relevant **Agreements**.
Short Term Flicker Severity	means a measure of the visual severity of flicker derived from the time series output of a flicker meter over a ten (10) minute period and as such provides an indication of the risk of **Customer** complaints as further set out in **Engineering Recommendation** P28.
Shutdown	means the condition of a **Generating Unit** where the generator rotor is at rest or on barring.
Significant Incident	means an **Event** that the **GSO** or a **User** considers have or may have a significant effect upon the **Grid System**.
Simultaneous Tap Change	means a tap change implemented on the generator step-up transformers of **Synchronized Dispatch Units**, effected by **Generators** in response to an instruction from the **GSO** issued simultaneously to the relevant **Power Stations.** The instruction, preceded by advance notice, must be effected as soon as possible and in any event within one (1) minute of receipt of the instruction from the **GSO**.

Term	Definition
Single Buyer	means any person or a unit, department or division forming part of a licensee who is authorized under subsection 22B(1) of Act 447.
Single Line Diagram	means a schematic representation of a three-phase network, with the three phases being represented by single lines. The diagram shall include (but shall not necessarily be limited to) busbars, overhead lines, underground cables, power transformers, and reactive compensation equipment. It shall also show where **Generating Modules** are connected, and the points where **Demand** is supplied.
Single Point of Connection	means a single **Point of Connection**, with no interconnection through the **User's System** to another **Point of Connection**.
Site	means a physical location that accommodates all the **Plant**, **Apparatus** and **Equipment** related to a connection to the **Grid System**.
Site Common Drawings	means the drawings prepared for each **Connection Site** which incorporates **Connection Site** layout drawings, electrical layout drawings, common protection/ control drawings and common services drawings.
Site Responsibility Schedule	means a schedule containing the information and prepared on the basis of the provisions set out in Appendix 1 of the **Connection Code**.
Special Protection Arrangement	means the arrangement pertaining to the special protection devices, their settings and their sequence of operation.
SPS	means **Special Protection Scheme,** which refers to protection measures other than the normal protection measures specified in this **Grid Code** that may be required by the **GSO** and **Grid Owner** to ensure safe, secure and stable operation of the **Grid System**. Some of these measures may be temporary or interim subject to completion of certain system developments while others may be permanent due to specific parameters of the **Plant** connected to the **Grid System**.

Term	Definition
Spinning Reserve	means the level of output in a whole number of MW at which a **Generating Unit** should operate to give the maximum capability to contribute to **Operating Reserve**.
Spinning Reserve Level	means the minimum level of output in a whole number of MW at which a **Dispatch Unit** or **Interconnection Transfer** should operate to be capable of attaining **Registered Capacity** within five (5) minutes**.**
Spinning Response	means the dynamic MW output response available from the **Generating Unit** already synchronized to and operating on the **Grid System**.
Stability Limits	means the limits that a **Generating Unit** can be stably operated within, either in terms of its rotor angle returning to a steady-state position after a **Grid System** disturbance or in terms of the minimum load at which its prime mover can stably operate.
Standards	means the **Standards** that may apply to **Reliability of Supply**, **Security of Supply** or **Quality of Supply** or **Plant** or **Apparatus** or **Equipment** or specific procedures.
Standard Planning Data	means the general data required by the **Grid Owner** under the **PC**. It is generally also the data that the **Grid Owner** requires from a new **User** in a connection application and from an existing **User** in an application for a new or varied connection, as reflected in the **PC**.
Stand-by Fuel	means the fuel defined by the **Single Buyer** as the stand-by fuel as part of the relevant **Agreement**.
Stand-by Fuel Stock	means the stock level for the **Stand-by Fuel** defined by the **Single Buyer** as part of the relevant **Agreement**.
Start-up	means the action of bringing a **Generating Unit** from **Shutdown** to **Synchronous Speed**.
STATCOM	means a static synchronous generator operated without an external electric energy source as a shunt-connected static VAR compensator whose capacitive or inductive output current can be controlled independently from the AC system voltage. The

Term	Definition
	STATCOM may include a transiently rated energy storage or energy absorbing device to enhance the dynamic behaviour of the power system by additional temporary real power compensation.
SOC	means **State Of Charge,** which refers to the State Of Charge of a **Battery Energy Storage System** is the ratio between the available energy from the **BESS** and the actual energy capacity, typically expressed as a percentage.
SVC	means **Static Var Compensator,** which refers to a shunt-connected static VAR generator/absorber whose output is adjusted to exchange capacitive or inductive current so as to maintain or control specific parameters of the electrical power system (typically busbar voltage).
Station Board	means a switchboard through which electrical power is supplied to the **Auxiliaries** of a **Power Station**, and supplied by a **Station Transformer**. It may be interconnected with a **Unit Board.**
Station Transformer	means a transformer supplying electrical power to the **Auxiliaries** of a **Power Station**, which is not directly connected to the **Generating Unit** terminals (typical voltage ratios being 132/11kV, 275/11kV or 500/22kV).
Steam Unit	means a **Generating Unit** whose prime mover converts the heat-energy in steam into mechanical energy.
Subtransmission System	means the part of a **User's System** that operates at a single transformation level below a 500kV and 275kV and 132kV.
Switching Operation Record	means a written document maintained by the **GSO** and each **User** of all switching operation carried out in the **Grid System** and the **User System** respectively.
Synchronization	means the process of bringing a **Generating Unit** to synchronous speed (frequency) and rated output voltage and closing the generator circuit breaker when the **System** and generator are at the same frequency and the generator and system voltages remain within a specific phase angle separation. In the case of **Power Park Module** it is the process of connecting the **Power Park Module** to

Term	Definition
	the busbars of another **System** so that the **Frequencies** and phase relationships of the **Power Park Module** and the **System** to which it is connected are identical.
Synchronized	means the condition where an incoming **Generating Module** or **System** is connected to the busbars of another **System** so that the **Frequencies** and phase relationships of that **Generating Unit** or **System**, as the case may be, and the **System** to which it is connected are identical.
Synchronized CDGU	means a **Centrally Dispatched Generating Unit** that is synchronized to the **Grid System**.
Synchronizing	means the condition where an incoming **Generating Module** or **System** is connected to the busbars of another **System** so that the **Frequencies** and phase relationships of that **Generating Unit** or **System**, as the case may be, and the **System** to which it is connected are identical, like terms shall be construed accordingly.
Synchronising Generation	means the amount of MW (in whole MW) produced at the moment of synchronising.
Synchronous Generating Module	means **Generating Module** consisting of synchronous **Generating Units** joined together by a System with a single electrical point of connection directly to the **Grid System**.
Synchronising Group	means a group of two or more **Dispatch Units** at a **Power Station**.
Synchronous Speed	means the speed required by a **Generating Unit** to enable it to be **Synchronized** to a **System**.
System	means any **User System** and/or the **Grid System**, as the case may be.
System Constraint	means the limit on the operation of the Grid System due thermal rating, stability consideration, voltage consideration and other limits.
System Constrained Capacity	means the portion of **Registered Capacity** not available due to a **System Constraint**.

Term	Definition
System Constraint Group	means a part of the **Grid System** which, because of **System Constraints,** is subject to limits of **Active Power** which can flow into or out of that part.
System Development Statement	means a statement, prepared by the **Single Buyer** showing for each of the ten (10) succeeding years, the opportunities available for connecting to and using the **Grid System** and indicating those parts of the **Grid System** most suited to new connections and transport of further quantities of electricity.
Dp	means **System Fault Dependability Index,** which refers to a measure of the ability of **Protection** to initiate successful tripping of circuit-breakers which are associated with a faulty item of **Apparatus**. It is calculated using the formula: **Dp** = $1 - F_1/A$ where: A = Total number of **System** faults F_1 = Number of System faults where there was a failure to trip a circuit-breaker.
System Frequency	has the same meaning as **Frequency**.
System Stress	means the condition of the **Grid System** when the **GSO** reasonably considers that a single credible incident would most probably result in the occurrence of **Power Islands** or **Partial Blackout** or **Total Blackout**.
System Voltage	has the same meaning as **Voltage**.
System Warning	means a warning issued by the **GSO** to certain **Users** to alert the **Users** to possible or actual **Plant** shortage, **System Problems** and/or **Demand Reductions**.
Target Frequency	means the **Frequency** determined by the **GSO**, in its reasonable opinion, as the desired operating **Frequency** of the **Power System**. This will normally be 50.00 Hz plus or minus 0.1 Hz, except in exceptional circumstances as determined by the **GSO**, in its reasonable opinion when this may be 49.50 or 50.50 Hz. An

Term	Definition
	example of exceptional circumstances may be difficulties caused in operating the **System** during periods of fuel supply problems.
Technical Specification	In relation to **Plant** and **Apparatus,** means the relevant Malaysian or **International Technical Specification**.
Tertiary Response	means the automatic or manual response by a Unit in order to restore an adequate level of Primary and Secondary Reserve or to provide desired (in term of economic considerations) allocation of these reserves within the set of Units included in the Spinning Reserve or the Non Spinning Reserve
Test Programme	means a programme submitted by the **Test Proposer** to the **Grid Owner**, **GSO** and each **User** identified by the **GSO** under **OC11**, that states the switching sequence and proposed timings of the switching sequence, a list of those staff involved in carrying out the **System Test** (including those responsible for the site safety) and such other matters as the **GSO** deems appropriate.
Test Proposal Notice	means the notice submitted by the **Test Proposer** to the **GSO**.
Test Proposer	means the person who submits a **Proposal Notice**.
Thermal Unit	means the **Generating Unit** where the prime movers and/or driving turbines are driven by steam or combustion of various fossil fuels.
Total Blackout	means the situation existing when all generation has ceased and there is no electricity supply from **External Interconnections** and, therefore, the **Power System** has shutdown with the result that it is not possible for the **Power System** to begin to function again without **GSO's** directions relating to a **Black Start**.
Total Harmonic Distortion	means the square root of the sum of the squares of all harmonics expressed as a percentage of the magnitude of the fundamental. 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.
TPA	means Third-Party Access, which refers to the possibility, granted by the law, to access to the Grid System, in an objective and non-discriminatory manner, under regulated conditions and according

Term	Definition
	to defined tariffs for the use of the grid. The conditions and tariffs are validated by the Energy Commission.
Transmission Capacity	means the ability of a network or a connection to transmit electricity.
Transmission Constraints	means the constraints such as limitation of power flow due to **Transmission** circuit outages or reduced reactive power output from or outages of **Generators** or **Reactive Compensation Equipment** or inadequate ratings of **Transmission Plant** under certain operational conditions.
Transmission Development Plan	means an annual statement prepared by the **Grid Owner** for submission to the **Commission** identifying the **Grid System** developments required to ensure compliance with the **Licence Standards** in accordance with the procedures in the **Planning Code** and data received from **Users**.
Transmission Reliability Standard	means the **License Standard** which applies to provision of sufficient **Transmission Capacity**, operational facilities, maintenance activity and co-ordination with **Generation** and **Distribution Functions** to enable continued supply of electric energy to the **Distribution Networks** and **Grid Connected Customers**. This **Standard** is used by the **Grid Owner** to determine the investment requirements for the **Grid System** and **GSO** operational facilities and implement the necessary measures.
Transmission System Power Quality Standards	means the **License Standards** specifying the **Power Quality** requirements of the bulk supply to be delivered to the **Distribution Network**, at the bulk **Demand Connection Points** where any **Distribution Network** or **User System** is connected to the **Grid System** in terms of stable **Voltage** and **Frequency** within specific limits so that **Generator's** or **User's** equipment directly connected to the **Grid System** can operate safely within its design performance without suffering undue damage or breakdown.
Transmission System Reliability Standards	means The Reliability Standards comprising the: *(a)* the **Generation Reliability Standard**; and

Term	Definition
	(b) the **Transmission Reliability Standard.**
Two Shifting Limit	means the maximum number of times in any **Schedule Day** that a **CDGU** may **De-Synchronize** (which, for the purpose of this definition, is deemed to occur at the **De-Synchronising** time included in (or which can be calculated from) the **Dispatch** instruction.
Under Frequency Relay	means an electrical measuring relay intended to operate when its characteristic quantity the **Frequency** reaches the relay settings by a decrease in **System Frequency**.
Unit Board	means a switchboard through which electrical power is supplied to the **Auxiliaries** of a **Generating Module** and which is supplied by a **Unit Transformer.** It may be interconnected with a **Station Board**.
Unit Scheduling	means the activity of Scheduling the **Dispatch Units** for operation the next day in an order to meet the changing **Demand** over the twenty four (24) hour period from midnight on the day before to midnight the next day.
Unit Schedule	means a statement, prepared and issued by the **Single Buyer** under **SDC1**, of which **Dispatch Units** and I**nterconnector Transfers** may be required to ensure, so far as possible, the integrity of the **Grid System**, the security and quality of supply and that there is sufficient generation to meet **Demand to the possible extent** at all times, together with an appropriate margin of reserve.
Unit Scheduling and Dispatch Parameters	means the parameters listed in **SDC1** under the heading **Unit Scheduling and Dispatch Parameters** relating to **Dispatch Units.**
Unit Transformer	means a transformer directly connected to a **Generating Module's** terminals, which supplies power to the **Auxiliaries** of a **Generating Unit**. Typical voltage ratios are 23/11kV and 15/6.6kV.
Unplanned Outage	means an outage of **Power Station** or of part of the **Grid System**, or of part of a **User System**, that has not been planned under **OC2**.

Term	Definition
User	means a term utilised in various sections of the **Grid Code** to refer to the persons using the **Grid System**, as more particularly identified in each section of the **Grid Code** concerned. In the **Preface** and the **General Conditions** the term means any person to whom the **Grid Code** applies.
User Development	In the **PC** this means either **User's Plant** and/or **Apparatus** that is to be connected to the **Grid System**, or a **Modification** relating to a **User's Plant** and/or **Apparatus** already connected to the **Grid System**, or a proposed new connection or **Modification** to the connection within the **User System**.
User's HV Apparatus	means **HV Apparatus** owned by the **User**.
User's Metering Installation	means a **Metering Installation** owned by a **User**.
User's Operation Diagram	means the **Operation Diagram** prepared by the **User**.
User's Plant and/or **Apparatus**	means the **Plant** and/or **Apparatus** owned or operated by a **User.**
User's Responsible Engineer/Operator	means a person nominated by a **User** to be responsible for **System** control.
User's Safety Rules	means the **Safety Rules** prepared and implemented by a **User** at the **User Sites**.
User's Site	means a site owned or occupied pursuant to a lease, licence or other agreement by a **User** where there is a **Connection Point**. For the avoidance of doubt, a site owned by the **Grid Owner** but occupied by a **User** as aforesaid, is a **User Site**.
User's Subtransmission System	means the part of a **User's System** which operates at a single transformation level below a 500 kV and 275 kV and 132 kV.
User's System or User System	means any system owned or operated by a **User** comprising:- *(a)* **Generating Modules;** *(b)* **Energy Storage Units;** and/or

Term	Definition
	(c) systems consisting (wholly or mainly) of electric lines used for the distribution of electricity from **Grid Supply Points** or **Generating Modules** or other entry points to the point of delivery to **Customers**, or other **Users**; and **Plant** and/or **Apparatus** connecting — *(a)* the system as described above; or *(b)* Non-Embedded Customers equipment; to the **Grid System** or to the relevant other **User System**, as the case may be.
User's Safety Rules	means the rules of a **User** that seek to ensure that persons working on **Plant** and/or **Apparatus** to which the rules apply are safeguarded from hazards arising from the **User's System**.
VDCL	means **Voltage Dependent Current Limits,** which refers to the voltage dependent operating current limits set within the control system of the converter equipment of an **HVDC Interconnection** providing the appropriate overcurrent protection to the converter equipment.
Voltage	means the Electric potential or electro motive force (emf) expressed in volts.
Vulnerability	means a weakness, susceptibility or flaw of an ICT asset or a system that can be exploited by a cyber threat.
Vulnerability Assessment	means a process of identifying and quantifying vulnerabilities.
Wide Area Measurement System (WAMS)	means an enabling technology based on an information facility with monitoring purposes to improve situational awareness and visibility within power systems. Based on **Phasor Measurements Units** (PMUs), WAMS allow monitoring time-synchronized transmission system conditions over large areas in view of detecting and further counteracting grid instabilities. As mentioned above, such an early warning system contributes to increasing system reliability and can

Term	Definition
	be considered as an extension and enabler of an adaptive protection system.
Working Day	has the same meaning as **Business Day**.
Weekly Operational Plan	means a statement issued by the **GSO** each week (to **Generators,** as set out in **OC4**) of specific requirements to enable the **GSO** to operate the **Grid System** within the requirements of the **Licence Standards**.

<End of the Glossary and Definitions>

Planning Code (PC)

PC.1 Preamble

PC.1.1 The Grid Code is a code developed and issued by the Commission. The Grid Code is composed by a Main Code, containing the main provisions structuring the purpose, the scope, the governance and some general requirements, and by additional codes, containing the specific technical rules for different subjects related to the operation of the Grid system.

PC.1.2 According to section 50A of the Electricity Supply 1990 [Act 447], the Commission may develop and issue such additional codes as it deems fit and expedient or the Minister may direct from time to time, as the case may be.

PC.2 Amendment

PC.2.1 The Commission may at any time amend, modify, vary or revoke this Code or any part thereof.

PC.3 Introduction, Objectives and Scope

PC.3.1 The provisions of sections MPC.1, MPC.2 and MPC.3 of the Main Code shall apply to this Planning Code.

PC.4 Development of the Grid System and Applicable Standards

PC.4.1 The Grid Owner and the Single Buyer shall apply the Licence Standards relevant to planning, connection to and development of the Grid System. Potential Users may request connections to the Grid System which are above or below the established Licence Standards. In cases where potential Users have requested connections below the minimum required by the standards, the Grid Owner may refuse such a connection if it is likely to adversely affect other Users connected to the system. Requests for connections above the requirements of the Licence

Standards are subject to agreement between the Grid Owner and the potential User.

PC.4.2 The Grid Owner shall also apply the Licence Standards in ensuring compatibility of the connections from the Grid System to Distribution or Network Operator Systems or User Systems, as the case may be.

PC.4.3 The Users shall also apply, fully consider and comply with the Licence Standards relevant to planning, connection to and development of the Grid System, in the development of their own Power Stations, Distribution Networks and User Systems.

PC.4.4 The Commission may assess the opportunities for connection to and the future development of the system through the annual System Development Statement.

PC.4.5 The Single Buyer shall, by the end of each calendar year or as requested by the Commission, produce a System Development Statement presenting for each of the succeeding ten (10) years the opportunities available for connecting to and using the Grid System and indicating the parts of the Grid System that are most suited to new connections and transmission of further quantities of electricity. In particular the optimal result of location, connection to and potential induced development or reinforcement of the Grid System of capacity requirements identified within Generation Adequacy Planning shall be described. This shall take into account all the developments planned by the Grid Owner and the developments notified to the Grid Owner by the Users through connection applications and relevant Agreements.

PC.4.6 The System Development Statement, which is an output from the System Development Plan, is based on the integration of the Generation Development Plan and the Transmission Development Plan. The System Development Statement is under the responsibility of the Single Buyer and is submitted to the Commission by the Single Buyer. The System Development Statement identifies and evaluates the opportunities for connection in Peninsular Malaysia. The document shall include but not limited to the following:

(a) Grid System and background to system development, prepared by and under responsibility of the Grid Owner;

(b) Aggregated load forecast, prepared by and under the responsibility of the Single Buyer;

(c) Power Station capacity developments, including existing and Licensed Power Stations and Power Stations under construction, prepared by and under the responsibility of the Single Buyer;

(d) Power Station capacity requirements for compliance with Generation Reliability Standard, prepared by and under the responsibility of the Single Buyer;

(e) Existing and planned transmission developments, including the requirements for equipment replacements and technology up-grades, prepared by and under the responsibility of the Grid Owner;

(f) Grid System capability, including load flows and system fault levels, prepared by and under the responsibility of the Grid Owner;

(g) Grid System performance information, including frequency and voltage excursions and fault statistics, prepared by and under the responsibility of the Grid Owner;

(h) Commentary indicating the parts of the Grid System considered most suited to new connections and transport of further quantities of electricity, prepared by and under the responsibility of the Single Buyer. This commentary shall mention the impact of such new connections on the Transmission System Plan.

PC.4.7 Upon receival of an application for connection or a modification to a Connection Site, the Grid Owner shall carry out appropriate studies to recommend a connection arrangement that is compliant with the Grid Code for connection to the Grid System, based on the practices recommended in MS 2572:2014 “Guidelines for power system steady state, transient stability and reliability studies”.

PC.4.8 Grid Owner shall formally consult the GSO for operational considerations to be taken into account regarding the connection arrangement.

PC.4.9 The details for a Connection Application, or for a variation of an existing Connection, to be submitted by a User will include:

(a) a description of the Plant and/or Apparatus to be connected to the Grid System or of the Modification relating to the User's Plant and/or Apparatus already connected to the Grid System or, as the case may be, of the proposed new connection or Modification to the connection within the User System of the User, each of which shall be termed a "User Development" in the PC;

(b) the relevant Standard Planning Data as listed in DRC.7; and

(c) the desired Completion Date of the proposed User Development.

PC.4.10 The completed application form for a Connection Application, or for a variation of an existing Connection, as the case may be, will be sent to the Grid Owner as more particularly provided in the application form provided by the Grid Owner.

PC.4.11 Any offer of Connection, made by the Single Buyer, will provide that it must be accepted by the applicant User within the period stated in the offer, after which the offer automatically lapses. Acceptance of the offer renders the works relating to that User Development, reflected in the offer, committed and binds both parties to the terms of the offer. Within twenty-eight (28) days (or such longer period as the Single Buyer agrees in consultation with the Grid Owner may agree in any particular case) of acceptance of the offer the User shall supply the Detailed Planning Data to the Grid Owner pertaining to the User Development as listed in DRC.7 Schedules of Planning Data.

PC.4.12 On submission of the annual System Development Statement to the Commission, the Single Buyer shall fully brief the Commission on the generation requirements, connection opportunities and system developments for the next ten (10) years.

PC.5 The Planning Process

PC.5.1 General

PC.5.1.1 The Single Buyer shall annually (or according to the timeline as agreed with the Commission) prepare the System Development Plan, which shall include the items as described in PC.4.6 to ensure compliance with the Licence Standards for submission to the Commission doing so in accordance with the procedures and data received from Users as described in this PC5 and elsewhere in this Planning Code and the Data Registration Code.

PC.5.1.2 Each User shall submit Standard Planning Data and Detailed Planning Data, as more particularly specified in DRC.7. Where the User has more than one Connection Point then the appropriate data is required for each Connection Point.

PC.5.1.3 Data shall be submitted annually by the Users by the end of January in the current year "Year 0" and for each year for the ten (10) succeeding years.

PC.5.1.4 The Users shall submit data in writing on "by exception" basis submitting only the relevant changes to the data from the previous data submission or by declaring "no change" if this is the case.

PC.5.1.5 It is the responsibility of the User to submit accurate data in relation to its planned developments and the timescales in which these developments will be implemented. The Users also have the responsibility of notifying any changes to their planned developments without waiting for the annual data submission.

PC.5.1.6 In order to enable an agreement to be reached with the User over any changes and/or developments proposed, the Grid Owner shall notify each User of any material modifications of their annual Transmission Development Plan submissions that may concern that User.

PC.5.1.7 To enable Users to model the Grid System in relation to short circuit current contributions, the Grid Owner is required to submit to Users the Network Data as listed in DRC.7.11. The data will be submitted in December of each year and will cover the following five (5) years.

PC.5.2 Demand (Load) Forecasting

PC.5.2.1 The primary responsibility to forecast the electricity Demand (Load) and electrical Energy Requirements of customers in their respective areas, rests with the Distributors and Users with User Systems as specified in the terms of their respective Licenses. The demand forecasts shall be prepared to include the data specified in DRC.7.6 and DRC.7.7 and any additional data or clarification that may be requested by the Grid Owner and/or Single Buyer.

PC.5.2.2 As part of the preparation of the annual System Development Statement as in PC.4, Generation Development Plan by Single Buyer as in PC.5.3 and preparation of Transmission Development Plan by the Grid Owner, the Single Buyer shall have the responsibility to produce the System Demand (Load) and Energy Requirement forecast. In preparing the Demand Forecast the Single Buyer may consider data received from Distributors and Users with User Systems as and when necessary. The System Demand (Load) and Energy Requirements forecast prepared by the Single Buyer covering the next ten (10) succeeding years shall form the basis for the preparation of the annual System Development Statement by the Single Buyer.

PC.5.2.3 The Distributors and Network Operators and Users with User Systems shall notify the Single Buyer of any material changes to their forecasts of Demand (Load) and electrical Energy Requirements at the end of January and at the end of July each year, as may be requested by the Single Buyer.

PC.5.2.4 The Single Buyer shall fully take the Demand (Load) and Energy that has been contracted from Externally Interconnected Party into account in the preparation of the annual System Demand (Load) and Energy Requirements covering the next ten (10) succeeding years.

PC.5.2.5 It is the responsibility of the User to submit accurate data in relation to its planned developments and the timescales in which these developments will be implemented. The Users also have the responsibility of notifying any changes to their planned developments without waiting for the annual data submission.

PC.5.2.6 In order to enable an agreement to be reached with the User over any changes and/or developments proposed, the Grid Owner shall notify each User of any material modifications of their annual Transmission Development Plan submissions that may concern that User.

PC.5.3 Generation Adequacy Planning

PC.5.3.1 Single Buyer is required to annually calculate the generation adequacy and capacity requirements for the next ten (10) succeeding years and to notify the Commission of these requirements in a Generation Development Plan.

PC.5.3.2 In annually preparing the generation adequacy and capacity requirements for the next ten (10) succeeding years, the Single Buyer shall fully take into account the demand forecast scenarios taking into account the following factors:

(a) the System Demand (Load) and Energy Requirements forecast prepared by the Single Buyer covering the next ten (10) succeeding years reflecting the annual load curve;

(b) the amount and nature of the existing Generation Capacity at the time of the preparation of the calculations, the scheduled and forced outage rates of the existing Power Station and its scheduled outage programmes and durations of those outages for maintenance; if scheduled outage provided by Users does not cover the full 10 years period the Single Buyer will extrapolate available data provided for the 5 years ahead;

(c) Power Station already approved and under construction and typical scheduled and forced outage rates and duration of such outages;

(d) the Demand (Load) and Energy that has been contracted by the Single Buyer from Externally Interconnected Party;

(e) National and International Economic growth forecasts;

(f) electrical and other forms of energy sale statistics and market share data; and

(g) Government of Malaysia fuel and energy policy.

PC.5.3.3 In preparing the annual Generation Development Plan, the Single Buyer shall apply the security and connection criteria included in the Generation Reliability Standard forming part of the Licence Standards.

PC.5.3.4 In addition to applying the LOLP based Generation Reliability Standard, the Single Buyer shall also take into account the size of the largest Generating Unit connected to the system or the largest import across an Interconnection that can be accommodated on the system.

PC.5.3.5 It is the duty of the Single Buyer and the GSO to carry out calculations that quantify the technical and financial impact of introducing Generating Unit sizes or Interconnection import which increases the Largest Power Infeed Loss Risk (due to the loss of the largest generator or Interconnection import), specified in the Generation Reliability Standard. This quantification shall evaluate the additional dynamic Spinning Reserve (to be evaluated by the GSO) that would be required and an assessment by the GSO as to whether frequency control within the limits specified in the Transmission Reliability Standards could be achieved under all possible system demand periods from peak to minimum system load and special days. The financial impact of the additional dynamic Spinning Reserve that would be required to meet the particular Demand due to the introduction of Generating Unit sizes or Interconnection import which increases the Largest Power Infeed Loss Risk shall be calculated by Single Buyer. The consolidated report will be prepared by Single Buyer.

PC.5.3.6 In preparing the annual Generation Development Plan, the Single Buyer shall use appropriate parameters for the existing Power Station submitted in accordance with the provisions of this PC and data relating to performance and availability of such plant as continually recorded by the GSO. For any plant, which has yet not been planned, the Single Buyer shall use typical parameters applicable to such plant in international practice. The list of data to be used in Single Buyer studies in relation to the Generation Reliability Standard is included in DRC.7.10.

PC.5.3.7 When assessing the annual Generation Plan, the GSO shall provide the Single Buyer with results of the calculations of inertia resulting from the expected generation mix.

PC.5.3.8 When calculating the capacity requirements for the next 10 (ten) following years, the Single Buyer shall evaluate the optimal location of this capacity requirements regarding connection to and development or reinforcement of the Grid System. The Grid Owner and the GSO shall provide relevant information to the Single Buyer for this analysis.

PC.5.3.9 The Generation Plan elaborated by the Single Buyer should be the result of an optimization accounting for:

(a) The relevant technologies of generation units;

(b) The technical and economic viability for new generation candidates;

(c) When the connections can be made available;

(d) Corresponding available transmission capacities

PC.5.3.10 The Single Buyer shall consider the transmission network capability and issues using data provided by the Grid Owner and the GSO, use a relevant software for multi-node analysis and, when necessary, complement this analysis with a transmission planning and analysis software.

PC.5.4 Transmission Adequacy Planning

PC.5.4.1 The Grid Owner shall apply the Licence Standards relevant to planning and development, in the planning and development of the Grid System. Full application of the Licence Standards shall be deemed to provide transmission adequacy for the Grid System and adequacy of connections to generation and demand at the planning stage by the Grid Owner.

PC.5.4.2 The Grid Owner shall report the compliance of the Grid System with the Licence Standards on an annual basis to the Commission in a Transmission Development Plan. The report shall include transmission expansion plans for new connections and extensions to the Grid System. It shall also include the compliance status of the Grid System and the reasons for certain cases of non-compliance together with the proposed remedies and timescales for implementation of those remedies by the end of December each year.

PC.5.4.3 Each User shall also report the compliance of their User Systems with the appropriate Licence Standards and their compatibility at the connection points as well as the adequacy of their connections on an annual basis to the Commission and the Grid Owner by the end of December each year.

PC.5.4.4 The compliance reporting to the Commission as part of the Transmission Development Plan shall be in writing on a “by exception” basis, in that only the non-compliant items shall be reported together with a general statement confirming the compliance of the remainder.

PC.5.4.5 Inaccurate or false reporting of compliance shall be deemed to be a serious breach of this Grid Code, as it can lead to system failure.

PC.5.4.6 The Grid Owner shall produce every five (5) years a 20-years Transmission Development Plan to elaborate a long-term assessment of the Grid accounting for national energy policies. This Plan shall indicate main drivers of the Transmission developments and provide guidance for the annual Transmission Development Plan to ensure compliance with a long-term target.

PC.6 Connection Planning

PC.6.1 The Planning Data submission must be provided by a User when applying for a new connection or modifications to an existing connection to the Grid System. This data shall include any changes to the User System and the operating regime. In these submissions, the User must always provide Standard Planning Data. Provision of the Detailed Planning Data shall be at the request and in accordance with the requirements of the Grid Owner and/or Single Buyer. The notification shall also include a full timetable for the implementation and effective date at which the proposed connection or modifications will become fully operational.

PC.6.2 Following receival of an application for connection to the Grid System the Grid Owner will undertake the necessary studies to enable an offer of connection to be made by the Single Buyer within three (3) months of receival of the Standard Planning Data.

PC.6.3 The magnitude and complexity of any Grid System extension or reinforcement will vary according to the nature, location and timing of the proposed User Development which is the subject of the connection application and it may be necessary for the Grid Owner to carry out additional more extensive system studies to better evaluate the impact of the proposed User Development on the Grid System. Where in the opinion of the Grid Owner such additional more detailed studies are necessary to ensure the security of the Grid System the connection offer may indicate the areas that require more detailed analysis and before such additional studies are required, the User shall indicate whether it wishes the Grid Owner to undertake the studies necessary to proceed to enable the Single Buyer to make a revised offer within the three (3) month period normally allowed or such extended period which the Grid Owner may consider necessary.

PC.6.4 To enable the Grid Owner to carry out the necessary detailed system studies mentioned above, the User may, at the request of the Grid Owner, be required to provide some or all of the Detailed Planning Data stated in DRC Schedule 7 immediately after providing the Grid Owner with the Standard Planning Data, provided that the Grid Owner can reasonably demonstrate that it is relevant and necessary.

PC.7 Planning Data Requirements

PC.7.1 General

PC.7.1.1 It is the responsibility of the User to submit accurate data in relation to its planned developments and the timescales in which these developments will be implemented. The Users also have the responsibility of notifying any changes to their planned developments without waiting for the annual data submission.

PC.7.1.2 The Grid Owner and Single Buyer shall provide the relevant planning data (as specified in DRC7) as and when finalized to the GSO to what extent these are required for operational planning and scheduling.

PC.7.2 User Data

PC.7.2.1 The Planning Code, requires two types of data to be supplied by Users:

(a) Standard Planning Data; and

(b) Detailed Planning Data,

the details of the Standard Planning Data and Detailed Planning Data are set out in DRC.4.

PC.7.2.2 Where a User does not supply data within the timescale required under this PC, the Grid Owner may assume appropriate typical parameters that will be used in all the planning processes and studies but the responsibility of any consequence of the use of this data lies with the User.

<**End of the Planning Code**>

Connection Code (CC)

CC.1 Preamble

CC.1.1 The Grid Code is a a code developed and issued by the Commission. The Grid Code is composed by a Main Code, containing the main provisions structuring the purpose, the scope, the governance and some general requirements, and by additional codes, containing the specific technical rules for different subjects related to the operation of the Grid system.

CC.1.2 According to section 50A of the Electricity Supply 1990 [Act 447], the Commission may develop and issue such additional codes as it deems fit and expedient or the Minister may direct from time to time, as the case may be.

CC.2 Amendment

CC.2.1 The Commission may at any time amend, modify, vary or revoke this Code or any part thereof.

CC.3 Introduction, Objectives and Scope

CC.3.1 The provisions of paragraph CC.1, CC.2 and CC.3 of the Main Code shall apply to this Connection Code.

CC.4 Connection Principle

CC.4.1 The application process for seeking connection to or modification to an existing connection and the data submission requirements for this purpose are described in detail in the Planning Code of this Grid Code PC4.7, 4.8, 4.9 and 4.10. Each User seeking connection to or for modification to an existing connection shall complete the appropriate connection application form provided by the Grid Owner and the GSO. The completed application form for a Connection Application, or for a variation of an existing Connection, as the case may be, will be sent to the Grid

Owner and the GSO as more particularly provided in the application form provided by the Grid Owner and the GSO.

CC.4.2 The design and implementation of connections between Grid System and User System shall be in accordance and compliant with the Licence Standards and the Planning Code (PC). The design and implementation of metering installations shall be in accordance and compliant with Metering Code (MC). The connections will be operated in accordance and compliant with Operating Codes (OCs) and Scheduling and Dispatch Codes (SDCs).

CC.4.3 The Grid Owner and the GSO shall decide the point of connection, the connection scheme and the voltage at which the User shall be connected to the Grid System to enable sustained compliance with this Grid Code, taking into account the User's views. Generating Module and other Users seeking connection to or modifications to their existing connections to a User's System located in Peninsular Malaysia, shall consult the Grid Owner and the GSO in deciding the point and the voltage at which the new connection shall be made and that both the new and modified connection shall enable sustained compliance with this Grid Code.

CC.4.4 The relevant Agreements contain provisions relating to the procedure for connection to the Grid System or, in the case of Embedded Power Station or Generating Module type A, becoming operational. The relevant Agreements also include provisions relating to certain conditions to be complied with by Users prior to the Grid Owner and the GSO notifying the User that it has the right to become operational.

CC.5 Connection Process and Information Exchange

CC.5.1 The provisions relating to connecting to the Grid System or to a User's System as in the case of a connection of a Power Station or Generating Module type A are contained in the relevant Agreement with a User. These Agreements include provisions relating to both the submission of information and reports relating to compliance with the relevant Connection Code for that User, Safety Rules, commissioning programmes, Operation Diagrams and approval to connect.

CC.5.2 Prior to connection of a User's facility to the Grid System the following shall be submitted:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning 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 Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in CC.6;

(c) copies of all Safety Rules and Local Safety Instructions applicable at User's Sites which will be used at the Grid System/User interface (which, for the purpose of OC8, must be to the GSO's satisfaction regarding the procedures for Isolation and Earthing);

(d) information to enable the Grid Owner to prepare Site Responsibility Schedules on the basis of the provisions set out in Appendix 1 of this Connection Code;

(e) an Operation Diagram for all HV Apparatus on the User side of the Connection Point as described in CC.7;

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

(g) written confirmation that Safety Coordinators acting on behalf of the User are authorized and competent pursuant to the requirements of OC8;

(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, pursuant to OC7;

(i) a senior management representative who has been duly authorized to sign Site Responsibility Schedules on behalf of the User;

(j) information to enable the Grid Owner and the GSO to prepare Site Common Drawings as described in CC.7;

(k) a list of the email addresses referred to in CC.6.6.5; and

(l) a list of persons authorized for switching duties and testing.

CC.5.3 In addition, at the time the information is given under CC.5.2 (7), the Grid Owner in consultation with the GSO will provide written confirmation to the User that the Safety Coordinators acting on behalf of the Grid Owner are authorized and competent pursuant to the requirements of OC8.

CC.5.4 The Grid Owner and the GSO shall, at all stages in the connection process, table relevant information relating to studies and assessments carried out by the Grid Owner and the GSO in relation to the technical design and implementation of the connection. Such information will include, but will not be limited to, the following:

(a) load flow analysis;

(b) short circuit analysis;

(c) transient and steady-state stability analysis;

(d) annual and monthly demand duration curves;

(e) forced outage rates of Grid System circuits in the vicinity of the Connection Point to the User System.

CC.5.5 All Users shall identify data submitted pursuant to this CC that are required to be maintained as confidential and notify these to the Grid Owner and the GSO. This data shall be kept confidential.

CC.5.6 Any information disclosed to the User by the Grid Owner and the GSO in relation to its Connection Point shall be treated as “confidential” by the User and shall not be shared in any way by any other party without prior written permission of the Grid Owner and the GSO.

CC.6 Technical Design and Operational Criteria

CC.6.1 General

CC.6.1.1 The following is an overview of the technical design and operational criteria governing the design and operation of the Grid System. The full details of the technical design and operational criteria as well as the procedures followed by the Grid Owner and the GSO are presented in the Transmission System Reliability Standards, (TSRS) and the Transmission System Power Quality Standards, (TSPQS), which are included in the Licence Standards. For the avoidance of doubt, technical guides, where applicable are also part of the reference document that shall be consulted.

CC.6.2 Grid System Performance Characteristics

CC.6.2.1 That the Grid Owner and the GSO shall ensure that, subject to the provisions in this Grid Code and Licence Standards, the Grid System complies with the technical, design and operational criteria. In relation to operational criteria the GSO may be unable to comply with this obligation to the extent that —

(a) there is insufficient Generation or User System are not available; or

(b) the relevant Users do not comply with the GSO instructions or do not comply with the Grid Code.

CC.6.2.2 Each User shall also ensure that it’s Plant and Apparatus complies with the criteria set out in CC.6.2.5.

CC.6.2.3 Grid Frequency Variations

CC.6.2.3.1 The Frequency of the Grid System shall be nominally 50Hz and shall be controlled within the limits of 49.5Hz - 50.5Hz unless exceptional circumstances prevail.

CC.6.2.3.2 In exceptional circumstances, the System Frequency could rise to 52Hz or fall to 47Hz but sustained operation outside this range is not envisaged. Design of User's Plant and Apparatus must enable operation of that Plant and Apparatus within that range in accordance with the following, for each event occurring on the Grid System:

Frequency Range	Required Duration
51.5 – 52 Hz	60 minutes
50.5 – 51.5 Hz	90 minutes
49.5 – 50.5 Hz	continuous
48.5 – 49.5 Hz	90 minutes
47.5 – 48.5 Hz	90 minutes
47. – 47.5 Hz	10 seconds

CC.6.2.4 Grid System Voltage Variations

CC.6.2.4.1 Subject to the Licence Standards, in Normal Conditions and Abnormal Conditions, the voltage levels will remain within the values summarized in the table below:

Nominal Voltage Value	500 kV	275 kV	132 kV
Normal Conditions	+/- 5 %	+10 % - 5 %	+/- 10 %
Abnormal Conditions	+/- 10 %	+/- 10 %	+/- 10 %

Even during abnormal conditions, the high-voltage level will not last longer than 15 minutes between +5 % and +10 %.

CC.6.2.4.2 The Grid Owner and the GSO and a User may agree to greater or lesser variations in voltage to those set out above in relation to a particular Connection Site, and in so far as a greater or lesser variation is agreed, the relevant figure set out above shall, in relation to that User at the Connection Site, be replaced by the agreed figure.

CC.6.2.5 Voltage Waveform Quality

CC.6.2.5.1 All Plant and Apparatus connected to the Grid System, and that part of the Grid System at each Connection Site, should be capable of withstanding the following distortions of the voltage waveform in respect of harmonic content and phase unbalance:

(a) Harmonic Content means the maximum total levels of harmonic distortion on the Grid System from all sources under both Planned Outage and fault outage conditions, (unless abnormal conditions prevail) shall not exceed—

(i) at 500kV, 275kV and 132kV a Total Harmonic Distortion of 3.0%; and

(ii) the individual harmonic limits shall be compliant with limits as specified in the Licence Standards.

(b) Phase Unbalance - means the Under Planned Outage conditions, the maximum negative phase sequence component of the phase voltage on the Grid System should remain below 1% unless abnormal conditions prevail.

CC.6.2.5.2 Infrequent short duration peaks may be permitted to exceed the levels in CC6.2.5.1 (1) for harmonic distortion subject to the prior agreement of the Grid Owner and the GSO. The Grid Owner and the GSO will only agree after the completion of and subject to a satisfactory outcome of a specific assessment of the impact of these levels on the Grid Owner’s and other User’s Apparatus.

CC.6.2.5.3 Under the planned outage conditions, infrequent short duration peaks with a maximum value of 2% are permitted for Phase Unbalance, subject to the prior agreement of the Grid Owner and the GSO. The Grid Owner and the GSO will only agree following a specific assessment of the impact of these levels on the Grid Owner’s and other User’s Plant and Apparatus with which it is satisfied.

CC.6.2.5.4 All Generating Modules must remain operating continuously and connected to the Grid System on an unbalanced system in accordance to “Table 2 – Unbalanced operating conditions for synchronous machines” of IEC 60034-1.

CC.6.2.6 Load Unbalance

CC.6.2.6.1 At the terminals of a User's installation or specific Load the unbalance voltage shall not exceed 1% for five (5) occasions within any thirty (30) minutes time period.

CC.6.2.6.2 In terms of traction Loads connected to the Grid System, the acceptable limits of unbalance are in accordance with "Engineering Recommendation (E/R) P24, issued by the Electricity Council of UK in 1984 entitled 'AC Traction Supplies to British Rail' and its successor document P29 issued in 1990 'Planning Limits for Voltage unbalance in the United Kingdom". The Grid Owner and the GSO use the procedures contained in Licence Standards to plan the connection of Loads producing Unbalance and applies the limits therein by measuring and monitoring the levels of unbalance at such points of connection.

CC.6.2.7 Voltage Fluctuations

CC.6.2.7.1 Voltage fluctuations at a Connection Point with a fluctuating Load directly connected to the Grid System shall not exceed 1% of the voltage level for step changes, which may occur repetitively. Any large voltage excursions other than step changes or less frequent step changes may be allowed up to a level of 3% provided that this does not constitute a risk to the Grid System or, in the Grid Owner and the GSO's view, any other party connected to the System. All Users connected to the Grid System must comply with the requirements of the License Standards.

CC.6.2.7.2 The requirements regarding the Short-Term and Long-Term Flicker Severity are defined in the Licence Standards for Fluctuating Loads connected to the Grid System. The maximum values of these Short-Term and Long-Term Flicker Severity depend on the voltage level.

CC.6.3 Requirements for User's and Connected Network Equipment at the Connection Point

CC.6.3.1 Introduction

CC.6.3.1.1 The following requirements apply to Plant and Apparatus relating to the User/Connection Point, and each User, the Grid Owner and the GSO must ensure they are complied with.

CC.6.3.2 General Requirements

CC.6.3.2.1 The design of connections between the Grid System and —

(a) any Generating Module;

(b) any Network Operator's User System;

(c) Distributor;

(d) Grid Connected Customer's equipment;

(e) any Interconnection; or

(f) any Energy Storage Unit;

will be consistent with the Licence Standards.

CC.6.3.2.2 The Grid System at nominal System voltages of 132kV and above is designed to be earthed with an Earth Fault Factor of below 1.4. Under fault conditions the rated Frequency component of voltage could fall transiently to zero on one or more phases or rise to 140% phase-to-earth voltage. The voltage rise would last only for the time that the fault conditions exist. The fault conditions referred to here are those existing when the type of fault is single or two phase-to-earth.

CC.6.3.2.3 The Rated Insulation Levels to which all equipment are designed, procured and maintained are as given below:

Nominal Voltage (kV)	Rated Voltage (kV)	Power frequency withstand voltage (kV)	Switching impulse withstand voltage (kV)	Lighting impulse withstand voltage (kV)
500	550	620	1175	1550
275	300	380	850	1050
132	145	275	N/A	650

Grid Equipment Rated Insulation Levels

6.3.3 Substation Plant and Apparatus

CC.6.3.3.1 The following provisions shall apply to all Plant and Apparatus which is connected at the voltage of the User/Transmission Connection Point and which is contained in equipment bays that are within the Grid System busbar protection zone at the User/Transmission Connection Point. This includes, but not exclusively, circuit breakers, switch disconnectors, 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 devices. Where necessary, this may be more precisely defined in the relevant agreement:

(a) Plant and/or Apparatus prior to this Grid Code becoming effective - Each item of such Plant and/or Apparatus which was installed prior to this Grid Code becoming effective and is the subject of an Agreement with regards to the purpose for which it is in use or intended to be in use, shall comply with the relevant standards/specifications applicable at the time that the Plant and/or Apparatus was commissioned and any further requirements as specified in that Agreement.

(b) Plant and/or Apparatus for a new Connection Point after this Grid Code becoming effective - Each item of such Plant and/or Apparatus installed in relation to a new Connection Point after this Grid Code becomes effective shall comply with the relevant Technical Specifications and any further requirements identified by the Grid Owner and the GSO, acting reasonably, to reflect the options to be followed within the Technical Specifications and/or if necessary to complement the Technical Specifications so as to enable the Grid Owner and the GSO to comply with its obligations to the Grid System. This information, including the application dates of the relevant Technical Specifications, will be as specified in the relevant Agreement.

(c) User Plant and/or Apparatus being moved, re-used or modified - If, after its installation, any such item of Plant and/or Apparatus is subsequently:

(i) moved to a new location; or

(ii) used for a different purpose; or

(iii) otherwise modified.

then the standards/specifications as described in (a) or (b) above as applicable will apply to such Plant and/or Apparatus, which must be reasonably fit for its intended purpose due to the obligations of the Grid Owner and the GSO and the relevant User under their respective Licences. Use of the Plant and/or Apparatus at any site other than the original site of connection to the Grid System is subject to approval of the Grid Owner and the GSO.

CC.6.3.3.2 Plant and Apparatus to be connected to Grid System is required to meet and conform to relevant Technical Specifications and standards as agreed by the Grid Owner and the User and included in the relevant Agreement. These Technical Specifications and standards shall include:

(a) relevant Malaysian national standards (MS);

(b) relevant international, European technical standards, such as IEC, ISO and EN;

(c) other relevant national standards such as BS, DIN and ANSI, ASA; and/ or

(d) the Grid Owner technical specifications.

The User shall ensure that the specification of Plant and Apparatus at the Connection Point shall be such as to permit operation within the Licence Standards and the applicable safety procedures agreed between the Grid Owner, the GSO and the User.

CC.6.3.3.3 The Grid Owner shall maintain a list of those Technical Specifications and additional requirements which might be applicable under this CC6.3.3.2 and which may be referenced by the Single Buyer in consultation with the GSO in the relevant Agreement. The Grid Owner shall provide a copy of the list upon request to any User. The Grid Owner shall also provide a copy of the list to any new User upon receipt of an application form for an Agreement for a new Connection Point.

CC.6.3.3.4 When the User provides the Grid Owner with information and/or test reports relating to Plant and/or Apparatus that the User believes demonstrate the compliance of such items with a Technical Specification then the Grid Owner shall promptly without unreasonable delay give due and proper consideration to such information.

CC.6.3.3.5 Plant and Apparatus shall be designed, manufactured and tested in manufacturer premises or in independent testing premises with an accredited certificate in accordance with the quality assurance requirements of ISO/IEC 17025 standard (or equivalent as reasonably approved by the Grid Owner). The Grid Owner and/or their appointed independent Representatives shall have the right to witness such tests for final acceptance of the product.

CC.6.3.4 Requirements relating to Generator / Grid Owner Connection Points

CC.6.3.4.1 Each connection between a Generating Module or Energy Storage Unit and the Grid System must be controlled by a circuit breaker capable of interrupting the maximum short circuit current at the point of connection. A circuit breaker at the generator terminals is also required. The Generating Unit or Generating Module or Energy Storage Unit shall also have sufficient protection systems to prevent or limit damage to its generation and auxiliary equipment. The protection systems shall guard for contingencies both within and external to the Generating Unit or Generating Module or Energy Storage Unit. The values of short circuit current and the rating of the Grid Owner’s circuit breakers at existing and committed Connection Points for future years will be supplied to the Users seeking connection by the Grid Owner and the GSO on request.

CC.6.3.4.2 Protection of Generating Modules or Energy Storage Unit and their connections to the Grid System are necessary to reduce the impact of faults on circuits owned by Generators, on the Grid System to a practical minimum. The Grid Owner shall specify the scheme and the settings including the back-up protection and the breaker fail protection, necessary to protect the Grid System, taking into account the characteristics of the Generating Module. The protection schemes and settings required of the Generating Module or Energy Storage Unit and the Grid System must be coordinated and agreed between the Grid Owner and the Generator. The Grid Owner may require a Generating Module or an Energy Storage Unit, to install additional protection, where the Grid Owner can show the necessity for the security of the Grid System.

CC.6.3.4.3 Protection of Interconnecting Connections - The requirements for the provision of Protection equipment for interconnecting connections will be specified in the relevant agreement by the Single Buyer in consultation with the Grid Owner and the GSO. In this CC the term "interconnecting connections" means the primary conductors from the current transformer accommodation on the circuit side of the circuit breaker to the Connection Point

CC.6.3.4.4 Circuit-breaker Fail Protection - The Generator and Energy Storage Unit shall install Circuit Breaker Fail Protection equipment in accordance with the GO settings.

CC.6.3.4.5 Loss of Excitation Protection - The Generator shall provide Protection to detect loss of excitation on a synchronous Generating Module and initiate a Generating Module trip.

CC.6.3.4.6 Pole-Slipping Protection - Where, in the Grid Owner and the GSO’s reasonable opinion, System requirements dictate, the Grid Owner and the GSO shall specify a requirement for Generators to fit pole-slipping Protection on their Generating Units in the relevant Agreement.

CC.6.3.4.7 The Grid Owner and the GSO shall review the adequacy and the full applicability of the Special Protection Scheme on a regular basis in accordance with and as appropriate to the development of the Grid System. This review shall include any changes to operative settings of the control actions and any alterations to the overall operation or additional provisions for the Special Protection Scheme.

CC.6.3.4.8 Each Generating Module and Energy Storage Unit must remain synchronized to the Grid System in case the ROCOF remains below or equal to 2 Hz/s, measured over a rolling 500 millisecond period. In addition, the auxiliaries of the Generating Modules and the Energy Storage Unit must remain in operation for avoiding the tripping of the Generating Modules or Energy Storage Unit

CC.6.3.4.9 The GSO is in charge of determining the right level of ROCOF, the most relevant for the characteristics of the Grid System, by means of network studies. Based on the results of the studies, if necessary, GSO to review the appropriate value of ROCOF required for Generating Module and Energy Storage Unit.

CC.6.3.4.10 All PPM and Energy Storage Units shall be equipped with Anti Islanding Protection. The protections shall only operate for faults beyond fault ride through capability described in CC.6.415.2 (Figure for Power Park Modules and Energy Storage Units Fault Ride Through Requirements). Upon detection and operation of Anti Islanding Protection, the inverters shall cease operation.

CC.6.3.4.11 Signals for Revenue Metering - Generators shall install current and voltage transformers supplying all tariff meters at a voltage to be specified in, and in accordance with, the relevant Agreement and the Metering Code

CC.6.3.4.12 Users are not permitted to work on busbar Protection, mesh corner Protection, circuit-breaker fail Protection relays, or any other related inter-tripping protection scheme or any Special Protection Scheme, AC or DC wiring (other than power supplies or DC tripping associated with the Generating Module itself) may be worked upon or altered by the Generator personnel in the absence of a representative of the Grid Owner unless he has a written approval from the GSO or the Grid Owner.

CC.6.3.4.13 Relay Settings - Protection and relay settings will be co-ordinated (both on connection and subsequently) across the Connection Point in accordance with the approved Grid Owner's protection relaying scheme to ensure effective disconnection of faulty Apparatus.

CC.6.3.4.14 High Speed and Delayed Auto Reclosing

The Grid System is equipped with High-Speed and Delayed Auto Reclosing facilities with the general characteristics as given below to mitigate the impact of transmission line faults on the Grid System. These High-Speed and Delayed Auto Reclosers are equipped with synchro-check to avoid synchronization issues. The Generating Modules shall remain operational on the Grid System without tripping and adverse behaviour during and after the operation of the auto reclosing equipment.

System Voltage	High Speed Single-Pole	Delayed Three-Pole
500 kV	750 milliseconds	From 3 to 10 seconds
275 kV	750 milliseconds	From 3 to 10 seconds
132 kV	Not applicable	From 3 to 10 seconds

The value mentioned above is the minimum dead time setting for the auto-reclose relay. The total operating time for the successful completion of auto-reclose and circuit breaker closing will be longer, depending on the bus configurations and circumstances.

CC.6.3.5 Requirements relating to Network Operator/Grid Owner and Grid Connected Customers/ Connection Points

CC.6.3.5.1 Protection Arrangements for Network Operators and Grid Connected Customers.

Protection of Network Operator and Grid Connected Customers supplied from the Grid System is necessary to reduce the impact of faults on circuits owned by Grid Connected Customers, on Grid System, to a practical minimum. The GO shall specify the scheme and the settings necessary to protect the Grid System, including the back-up protection and the circuit breaker fail protection, taking into account the characteristics of the Users. The protection schemes and settings must be coordinated and agreed between the GO and the Grid Connected Customer.

CC.6.3.5.2 Fault Disconnection Facilities – Where no circuit breaker is provided by the Grid Owner at the User's connection voltage, the User must provide the means of tripping all the User's circuit breakers necessary to isolate faults or System abnormalities on the Grid System. In these circumstances, for faults on the User's System, the User's Protection should also trip higher voltage Grid System circuit breakers. These tripping facilities shall be in accordance with the requirements specified in the relevant Agreement.

CC.6.3.5.3 Automatic Switching Equipment – Where automatic reclosure of Grid System circuit breakers is required following faults on the User's System, automatic switching equipment shall be provided in accordance with the requirements specified in the relevant Agreement.

CC.6.3.5.4 Relay Settings – Protection and relay settings will be co-ordinated (both on connection and subsequently) across the Connection Point in accordance with the relevant Agreement to ensure effective disconnection of faulty Apparatus.

CC.6.3.5.5 Users are not permitted to work on busbar Protection, mesh corner Protection, circuit-breaker fail Protection relays, or any other related inter-tripping protection scheme or any Special Protection Scheme, AC or DC wiring (other than power supplies or DC tripping associated with the Apparatus of the Network Operator or Grid Connected Customer, as the case may be, itself). It may be worked upon or altered by the personnel of the Network Operator or the Grid Connected Customer, as the case may be, in the absence of a representative of the Grid Owner if the User has a written approval from the GSO or the Grid Owner.

CC.6.3.5.6 Protection of Interconnecting Connections – The requirements for the provision of Protection equipment for interconnecting connections will be specified in the relevant Agreement.

CC.6.3.5.7 High Speed and Delayed Auto Reclosing – The Grid System is equipped with High-Speed and Delayed Auto Reclosing facilities with the general characteristics as given below, to mitigate the impact of transmission line faults on the Grid System. The Network Operator or Grid Connected Customer. User’s System shall remain operational on the Grid System without tripping and adverse behaviour during and after the operation of the auto reclosing equipment.

System Voltage	High Speed Single-Pole	Delayed Three-Pole
500 kV	750 milliseconds	From 3 to 10 seconds
275 kV	750 milliseconds	From 3 to 10 seconds
132 kV	Not applicable	From 3 to 10 seconds

The value mentioned above is the minimum dead time setting for the auto-reclose relay. The total operating time for the successful completion of auto-reclose and circuit breaker closing will be longer, depending on the bus configurations and circumstances.

CC.6.3.5.8 Special Protection Scheme – Where in the Grid Owner and the GSO’s reasonable opinions as confirmed by studies there is need to install Plant and Equipment and operational measures to ensure stable operation of the Grid System the GSO will specify a requirement for the Grid Owner or a Distributor or a Network Operator or a Grid Connected Customer to implement the Special Protection Scheme on the Grid System or User System as specified by the GSO. The GSO shall review the adequacy and the full applicability of the Special Protection Scheme on a regular basis in line with Grid System development. This review will include any changes to operative settings of the Special Protection Scheme and any alterations to the overall operation of the scheme.

CC.6.3.5.9 Requirements to conduct test.

CC.6.3.5.9.1 Network Operator / Grid Owner and Grid Connected Customers shall be responsible for carrying out tests to prove compliance on the requirements stated in this CC.

CC.6.3.5.9.2 All commissioning tests shall meet at least the requirements stated in CC8.

CC.6.3.6 Ancillary Services

CC.6.3.6.1 The Ancillary Services are services, which can be proposed by the Generating Modules, the Energy Storage Units, the Aggregators, Distributors or the Grid Connected Customers. Such services are mandatory or voluntary and may depend on the type of Generating Modules.

The mandatory Ancillary Services are defined in this Grid Code, in the following articles. In addition to the mandatory services the Users can propose other services or the same services with additional performances, like faster contribution to frequency control for type B Generating Modules or frequency control for type A Generating Modules or other services, which are not mandatory or for the mandatory Ancillary Services, performances above the minimum described in this Grid Code. The Ancillary Services may concern the real time operation and/or the planning.

CC.6.4 General Requirements for Generating Modules

CC.6.4.1 Introduction

CC.6.4.1.1 This section sets out the technical and design criteria and performance requirements for Generating Modules and Energy Storage Units (whether directly connected to the Grid System or Embedded) of Type B, as defined in MCC3.3, which each Generator and Energy Storage Operator must ensure are complied with References for Generating Modules and Energy Storage Units in this CC6.4 should be read accordingly. In such cases the Grid Owner and the GSO shall provide appropriate provisions for inclusion in the relevant Agreement

CC.6.4.2 Plant Performance Requirements

CC.6.4.2.1 The short circuit ratio of the Synchronous Generating Modules shall be not less than 0.5.

CC.6.4.2.2 All Generating Modules and Energy Storage Units must provide to Grid Owner, GSO and the Single Buyer their Reactive Power Capability Curves.

All Generating Modules, except for Power Park Module, must be capable of supplying gross power output (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the Generating Unit terminals. All Generating Modules must also be capable of operating at any point within the capability chart corrected for the site conditions.

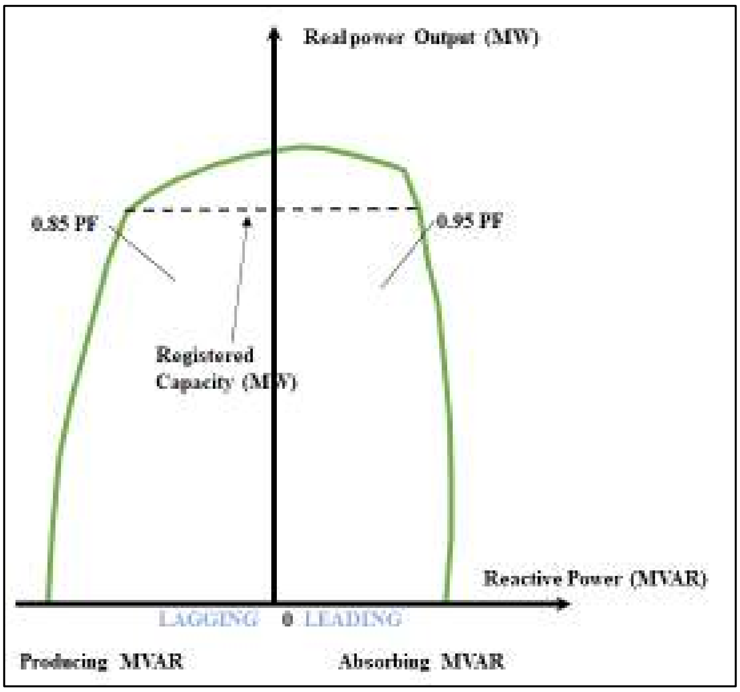


Figure 1 - Sample of Power Reactive Capability Curve for a synchronous generator

All Power Park Modules must be capable of generating Reactive Power at high voltage level of their step-up transformer at the Registered Capacity as per figure 2 below: 0.95 power factor leading (Point A) to 0.85 power factor lagging (Point B), in accordance with their Capability Curves. Each Power Park Module must also be capable of operating at any point within the agreed Reactive Power Capability Curve, as presented by the curve of A to C and B to D. The figure entitled "Power Park Module Reactive Power Requirement During Normal Operation" shown below for at all Active Power output levels under steady state voltage conditions. In the figure, 100% Active Power output is deemed as the Rated MW at the Connection Point.

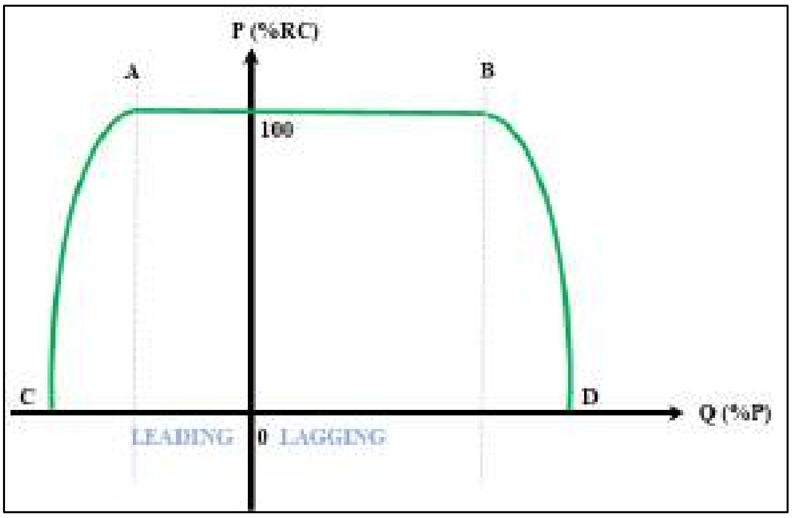


Figure 2 - Power Park Module Reactive Power Requirement During Normal Operation

All Energy Storage Units must be capable of generating Reactive Power at a high voltage level of their step-up transformer at the Registered Capacity. Figure 3 below shows the minimum required reactive capability characteristic for an Energy Storage Unit.

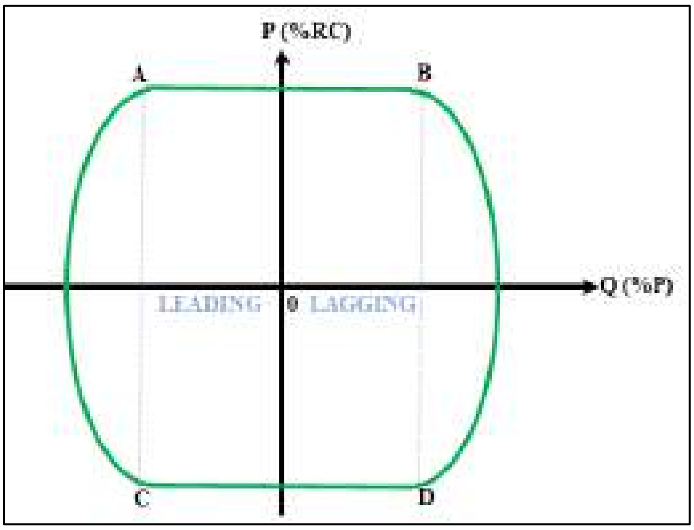


Figure 3 - Energy Storage Unit Reactive Power Requirement During Normal Operation

Points A and B are when the Energy Storage Unit is supplying maximum Active Power to the Grid (discharge mode) and C and D are when the Energy Storage Unit is consuming maximum Active Power from Grid (charging mode). Points A and C are when the Energy Storage Unit is absorbing Reactive Power at power factor of 0.9 leading (Q/P ratio of -0.33 and 0.33 respectively). Points B and D are when the Energy Storage Unit is generating Reactive Power at a power factor of 0.9 lagging (Q/P ratio of 0.62 and -0.62 respectively.

CC.6.4.2.3 The Generating Module and the Energy Storage Unit must be capable of —

(a) continuously maintaining constant Active Power output for System Frequency changes within the range 50.5 to 49.5 Hz, without taking into account the frequency.

(b) maintaining its Active Power output with a maximum admissible reduction from the Registered Capacity not greater than 2% of the registered capacity per 1 Hz frequency drop below 49.5 Hz.

CC.6.4.2.4 Notwithstanding the provisions specified in paragraph CC6.4.2.2, for System Frequency within the range of 52.0 Hz to 47.0 Hz all Power Park Modules or Energy Storage Unit shall have combination of the frequency response capabilities, which include but not limited to the following:

(a) Active power response proportional to frequency deviation i.e., droop response.

(b) Active power response proportional to calculated ROCOF.

(c) Active power response (ramp up to 100%) once triggered.

CC.6.4.2.5 The Active Power output under steady state conditions of any Generating Module and Energy Storage Unit directly connected to the Grid System should not be affected by voltage changes in the normal operating range specified in paragraph CC6.2.4. For Synchronous Generating Module the Reactive Power output under steady state conditions should be fully available within the voltage range (± 5) % at 500kV, 275kV and 132kV.

CC.6.4.2.6 For any Power Park Module or Energy Storage Unit, the Reactive Power output under steady state conditions, should be fully available within the range +/- 10% at 500kV, 275kV and 132kV where the requirement and limits shown in the figure below applies.

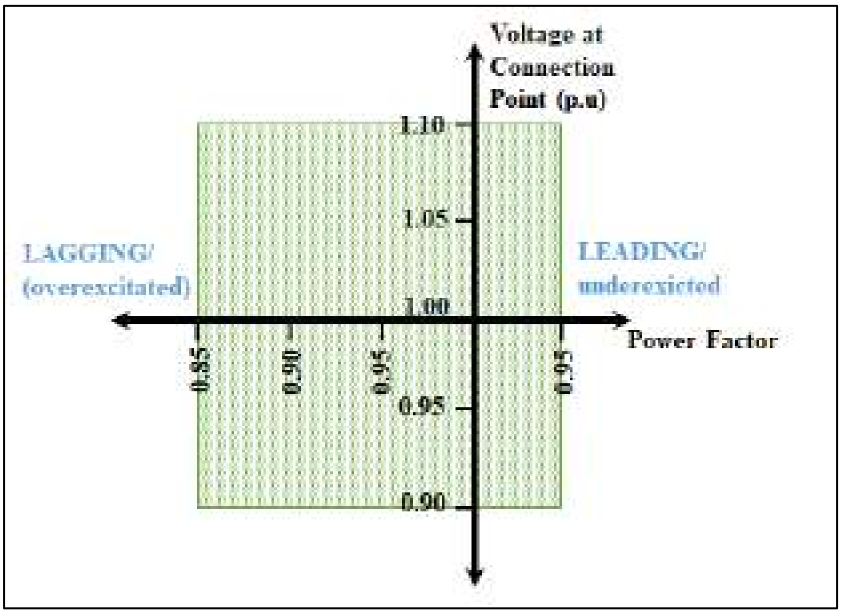


Figure 4 - Power Park Module and Energy Storage Unit Reactive Power Requirement During Normal Operation

Power Park Modules and Energy Storage Unit must be equipped with continuously acting automatic control to provide control of the voltage without instability over the entire operating range of the Power Park Module or Energy Storage Unit. Any Plants or Apparatus used in the provisions of such voltage control within the Power Park Module or Energy Storage Unit may be located at their terminals, an appropriate intermediate busbar or the Connection Point. When operating below 20% of Rated MW the automatic control system may continue to provide voltage control by utilising available reactive capability.

CC.6.4.3 Black Start Capability

CC.6.4.3.1 It is an essential requirement that the Grid System must incorporate a Black Start Capability. This will be achieved by identifying a number of strategically located Power Stations, where such Black Start Capability is required. The Grid Owner and the GSO shall do the identification in consultation with the User. In this respect, Black Start Capability relates to any one Generating Unit in a Power Station having the capability to start without any other back feed supply whatsoever being available from the Grid System and/or Distribution Network or from User System and subsequently the ability to start other Generating Units in the Power Station. The need for Black Start Capability between the GSO and the Single Buyer is defined in the relevant documents.

CC.6.4.4 Control Arrangements

CC.6.4.4.1 Each Generating Module, Power Park Module and Energy Storage Unit of type B must be capable of contributing to Frequency and Voltage control by continuous modulation of Active Power and Reactive Power supplied to the Grid System or the User System in which it is Embedded.

CC.6.4.4.2 Each Generating Module or Energy Storage Unit of type B must be fitted with a fast-acting proportional turbine speed governor and unit load controller or equivalent control device to provide Frequency response under normal operational conditions in accordance with Scheduling and Dispatch Code 3 (SDC3). The governor or its equivalent must be designed and operated to the appropriate Technical Specification acceptable to the Grid Owner and the GSO including:

(a) relevant Malaysian Specification;

(b) relevant International Specification;

(c) any other specification in common use acceptable to the Grid Owner and the GSO.

At the time when the installation was designed or when the modification or alteration was designed.

CC.6.4.4.3 The specification or other standard utilised in accordance with sub-paragraph CC6.4.4.2 (1), (2) or (3) will be notified to the Grid Owner and the GSO as part of the application for a Connection or as soon as possible prior to any modification or alteration to the governor or equivalent.

CC.6.4.4.4 Each Generating Module or Energy Storage Unit of Type B must be fitted with a speed governor or equivalent to control Active Power Output over the entire operating range, in co-ordination with other control devices.

CC.6.4.4.5 The speed governor or equivalent control device must meet the following minimum requirements:

(a) where a Generating Module or an Energy Storage Unit becomes isolated from the rest of the Grid System but is still supplying Customers, the speed governor or equivalent control must also be able to control System Frequency between 47.5 Hz to 52Hz unless this causes the Generating Module to operate below its Minimum Operating Level when it is possible that it may, as detailed in SDC3.5.2, trip after a time;

(b) the speed governor or equivalent control for the Generating Modules or an Energy Storage Unit of type B must be capable of being set so that it operates with an overall speed droop between 2% and 5%. Lower droop setting capability may be specified for Hydro Units by the Grid Owner and the GSO. In the case of Power Park Modules of type B, the relevant parameter equivalent to a speed droop shall be equal to a fixed setting (at a value set by the GSO) between 2% and 5% applied to each Power Park Unit in service; and/or

(c) in the case of all Generating Modules or Energy Storage Unit of type B the speed governor (or its equivalent) dead band should be adjustable as agreed with the GSO. However, the maximum combined effect of the frequency response insensibility and the frequency dead band cannot exceed 0.05Hz (for the avoidance of doubt, ±0.025Hz). In the case of the Steam Unit within a CCGT Module, the speed governor dead band should be set to an appropriate value consistent with the requirements of CC6.4.4.5(1) and the requirements of SDC3.2.4 for the provision of High Frequency Response.

CC.6.4.4.6 A facility to modify the Target Frequency setting either continuously or in a maximum of 0.05 Hz steps over at least the range 50 ± 0.1 Hz should be provided in the unit load controller or equivalent device so as to fulfil the requirements of the Scheduling and Dispatch Codes.

CC.6.4.4.7 Each Generating Unit and/or Generating Module or Energy Storage Unit must be able to meet the minimum frequency response requirement profile subject to and in accordance with the provisions of Appendix 3

CC.6.4.4.8 A continuously acting, static type, fast response automatic excitation control system, with Power System Stabiliser (PSS), is required to provide constant terminal voltage control of the Generating Unit without instability over the entire operating range of the Generating Unit. There is a requirement on the Generator to allow the Grid Owner and the GSO to witness commissioning tests. The automatic excitation control system shall remain in service at all times and shall not be removed or disabled from service without the GSO's prior consent.

CC.6.4.4.9 Other control facilities, including constant Reactive Power output control modes and constant power factor control modes (but excluding VAR limiters) are not required. However, if present in the excitation system or other appropriate control device they will be disabled unless otherwise agreed by written permission from the GSO. Operation of such control facilities will be in accordance with the provisions contained in SDC2. For the avoidance of doubt the Generating Module or Energy Storage Unit shall not be operated at any time under constant Reactive Power or constant power factor or any other specific control mode whatsoever without specific consent from the GSO.

CC.6.4.4.10 The excitation system shall also be equipped with a Power System Stabilizer (PSS) which must be capable of damping of power system oscillations over the frequency range of 0.1 to 5.0 Hz. The PSS shall be optimally tuned to damp out local and inter area oscillation modes with a Damping Ratio of not less than 5% while maintaining sufficient stability margins of the excitation control system. The Generator shall seek written advice from the Grid Owner and the GSO, on the values of the inter-area oscillation frequencies for which the PSS shall be tuned at the Preliminary Project Data stage as defined in the Planning Code.

CC.6.4.4.11 The use of Power Oscillation Damping (POD) control in inverters of Power Park Modules can be effectively designed and tuned to provide fast damping control and suppress small signal/low frequency oscillations - by modulating either active or reactive power of the inverters.

Power Park Modules must be equipped with POD control; designed and tuned to provide effective fast control to damp out small signal/low frequency oscillation of the identified mode(s) of oscillation, without destabilizing other modes of oscillations or unintentionally introducing new forms of stability concerns.

Power Park Modules must work closely with GSO to determine modes of oscillations, for proper design and tuning of the POD control.

CC.6.4.4.12 Before the commissioning of each Generating Unit and Power Park Module, they shall prove conclusively to the Grid Owner and the GSO that the PSS and POD have been optimally tuned to damp out the local and inter area oscillation modes, both analytically and by on site verification tests, including an actual line switching test. The Generator shall submit the PSS tuning study report to the Grid Owner and the GSO at least three (3) months before commissioning the Generating Unit.

CC.6.4.4.13 The control arrangements provided for Frequency and Voltage control shall continue to operate stably during disturbances experienced by the Grid System, without inadvertently tripping the turbine and/or prime mower or the Generator and disconnecting it from the Grid System.

CC.6.4.4.14 Each Generating Module shall provide the capability to rapidly adjust active power output upon receiving instruction from the GSO to preserve security of the Grid System. This feature can be used as a special protection measure to provide system wide protection. The target active power output upon fast load or deload shall be defined prior of activation of this feature.

CC.6.4.4.15 Each Generating Module or Energy Storage Unit of type B must be equipped with facilities to allow remote operations as defined in the technical documents, and management in monitoring and controlling directions by GSO Control Centre to meet all control arrangements, automated functions and special functions that have been specified by GSO. Technical documents relating to functional specifications, testing and commissioning needed to achieve these capabilities such as SCADA signalling and interfacing guideline, Energy Management System guideline for plant automated functions, generator testing guideline and energy storage testing guideline will be provided by GSO.

CC.6.4.5 Automatic Generation Control (AGC) and Load Following Capability

CC.6.4.5.1 Load Following on the Grid System shall be carried out automatically using Automatic Generation Control (AGC) control facilities at the GSO Control Centre. Unless otherwise specified by the GSO, the Generating Modules and Energy Storage Units of type B shall be equipped with appropriate plant controllers enabling AGC or automatic adjustment of generator output for Load Following purposes. The AGC shall be via the transmittal of a "desired generation output" signal from the GSO Control Centre and the plant controller will adjust the generator output accordingly. The Load Following assigned by the GSO Control Centre shall be shared by all Generating Units operating at the Power Station

CC.6.4.5.2 Each Power Station shall be designed to enable each Generating Module to be capable of Load Following over the whole range between the Minimum Generation and the Registered Capacity of the Generating Module. Load Following capability includes the following control actions by the Generating Unit:

(a) following a pre-set unit schedule;

(b) executing a Dispatch Instruction;

(c) for the type B Generating Module, performing AGC duties for the purpose of Load Following in the Grid System within a range of output (minimum and maximum values) agreed by the GSO, the Generator and the Single Buyer. The details on the facilities to affect this control capability shall be in accordance with the requirement stipulated in the related documents such as signalling, interfacing, functional testing and commissioning guidelines and relevant Agreement.

(d) for the type B Energy Storage Units, performing AGC duties for the purpose of Load Following in the Grid System within a range of output (minimum and maximum values), in both charging and discharging cycles, as agreed by the GSO, the Energy Storage Operator and the Single Buyer. The details on the facilities to affect this control capability shall be in accordance with the requirement stipulated in the related documents such as signalling, interfacing, functional testing and commissioning guidelines and relevant Agreement.

CC.6.4.5.3 The use of AGC shall not cause any restriction whatsoever on the operation of governors or equivalent control devices on the Generating Units and vice versa. In case of temporarily unavailability of the use of AGC, due to real time condition, the Operator of the Generating Module or Energy Storage Unit must inform the Operator of the GSO Control Centre.

CC.6.4.5.4 Each Power Park Module and Energy Storage Unit is to have Automatic Power Curtailment (APC) facility, which is the capability to reduce the Active Power output of a percentage between 10% to 100%, upon instruction by the GSO Control Centre either via telephony or telecontrol in order to safeguard operational security and reliability of the grid.

CC.6.4.6 Dispatch Inaccuracies

CC.6.4.6.1 The standard deviation of Load error at steady state Load over a thirty (30) minute period must not exceed (2) % or the percentage defined in the relevant Agreement, of a Centrally Dispatched Generating Modules capacity, in accordance with its Availability Declaration. When a Centrally Dispatched Generating Module or a Energy Storage Unit is instructed to Frequency sensitive operation, allowance will be made in determining whether there has been a dispatch error according to the governor droop characteristic registered under OC3. For the avoidance of doubt in the case of a Power Park Module allowance will be made for the full variation of power input which will not be constant over time.

CC.6.4.7 Negative Phase Sequence Loadings

CC.6.4.7.1 In addition to meeting the conditions specified in CC6.2.5.1(2), each Generating Module or Energy Storage Unit will be required to withstand, without tripping, the negative phase sequence loading incurred during the process of Back-Up Protection clearance of unbalance faults on the Grid System or User System in which it is Embedded, or during single pole auto-reclosing dead time, or during circuit breaker pole discordance event.

CC.6.4.8 Neutral Earthing

CC.6.4.8.1 At nominal System voltages of 132kV and above the higher voltage windings of a transformer of a Generating Module or Energy Storage Unit must be star connected with the star point suitable for connection to earth. The Earthing and lower voltage winding arrangement shall be such as to ensure that the Earth Fault Factor requirement of paragraph CC6.3.2.2 will be met on the Grid System at nominal System voltages of 132kV and above. Under single-phase-to-earth or two-phase-to earth fault conditions the rated frequency component of voltage could respectively fall transiently to zero on one or two phases or rise to 140 percent of phase-to-earth voltage.

CC.6.4.9 Frequency Sensitive Relays

CC.6.4.9.1 As stated in CC6.2.3.2, the System Frequency could rise to 52Hz or fall to 47Hz. Each Generating Module or Energy Storage Unit must continue to operate within this Frequency range for at least the periods of time given in CC6.2.3.2.

CC.6.4.9.2 Each Generating Unit in a Power Station or Generating Module or Energy Storage Unit, shall be equipped with appropriate under and over frequency relays. The relays shall be set to trip the high voltage circuit breakers when the Frequency of the Grid System reaches 47.0 Hz or when the frequency sustains itself at 47.5 Hz or lower for at least ten (10) seconds or when the frequency sustains above 52 Hz. The Generating Unit shall successfully go to House Load Operation as a result of such tripping. The settings of the frequency relays of the auxiliaries must be set like the relays do not trip before the tripping of their Generating Unit nor Generating Module nor Energy Storage Unit, so that the auxiliaries remain operational after the tripping of the Generating Unit due to under-frequency or over-frequency relays, with the time delay of the circuit breaker also taken into account. The relay shall be located within the Power Station. The relaying scheme shall comply with the Grid Owner's System Protection.

CC.6.4.9.3 Generators and Energy Storage Operators will be responsible for protecting all their Generating Modules or Energy Storage Units against damage should Frequency excursions outside the range of 52Hz to 47Hz ever occur. Should such excursions occur, it is up to the Generator to decide whether to disconnect his Apparatus for reasons of safety of Apparatus, Plant and/or personnel, in accordance with the CC6.4.9.2 requirements.

CC.6.4.9.4 It may be agreed in the relevant Agreement that a Dispatch Unit shall have a Fast-Start Capability. Such Dispatch Units may be used for Operating Reserve and their Start-Up may be initiated by Frequency-level relays with settings in the range 49Hz to 50Hz as specified pursuant to OC4.

CC.6.4.10 House Load Operation

CC.6.4.10.1 In the event of an abrupt de-energisation of the Interconnecting Connections, system disturbance or of complete Isolation between the Power Station and the Grid System (including disconnection of grid supply from the plant auxiliary systems), each Generating Unit must be capable of performing House Load Operation during a minimum of two (2) hours. Within such time, each Generating Unit shall be ready to be re-synchronized to the Grid System and able to increase output in the usual manner. House Load Operation capability shall be completely independent from the availability of supply from the Grid System. For the avoidance of doubt, requirement of house load operation does not apply to Power Park Module

CC.6.4.11 Unit Start for Active Power Reserve

CC.6.4.11.1 The GSO shall specify the requirements for Generating Module cold, warm and hot start for the provision of Active Power Reserve in consultation with the Generator for suitable incorporation in the relevant agreements by the Single Buyer. The regimes are defined as follow:

(a) hot State is the period of time following de-synchronization and lasts at maximum 12 hours to 10 hours.

(b) warm State is the period of time following the Hot State and last maximum 60 hours.

(c) cold State is the period of time starting after the end of the Warm State.

The Generator must provide to the GSO the characteristic of the cooling boundaries of their machines, which define the different states and vary in accordance with the type of machines.

CC.6.4.11.2 The Facility shall be capable of the following starting regimes:

(a) cold start;

(b) warm start; and/or

(c) hot start.

CC.6.4.12 Dispatch Ramp Rate

CC.6.4.12.1 The GSO shall specify the requirements for Generating Unit Dispatch Ramp Rate in consultation with the Generator for suitable incorporation in the relevant Agreements by the Single Buyer at the time of a connection application.

CC.6.4.13 Primary and Stand-by Fuel Stock

CC.6.4.13.1 The GSO shall specify the requirements for the Power Station Primary, Alternate and/or Stand-by Fuel Stock in consultation with the Generator for suitable incorporation in the relevant Agreements by the Single Buyer. This is to ensure that fuel stock obligations placed on the Electricity Industry are met. The requirements shall be defined in terms of the storage capacity and the stock level that should be maintained and included in the relevant Agreement.

CC.6.4.14 On-Line Fuel Changeover

CC.6.4.14.1 The GSO shall specify the requirements for On-Line Fuel Changeover at the Power Station and individual Generating Units within a Power Station in consultation with the Generator and the Single Buyer for suitable incorporation in the relevant Agreements at the time of a connection application to ensure the fuel changeover performance requirements are adequately met. These shall be included in the relevant Agreement.

CC.6.4.14.2 A Power Station whose Nominated Fuel is natural gas shall be capable of performing On-line Fuel automatic Changeover when the gas pressure drops within the safe operating limits and must be able to do a staggered On-line Fuel Changeover from natural gas to the Stand-by Fuel. Changeover from Stand-by Fuel back to the Nominated Fuel shall also be On-line and shall be manual.

CC.6.4.15 Loss of AC Power Supply and Fault Ride Through

CC.6.4.15.1 Each Generating Unit in a Power Station or Power Park Module or Energy Storage Unit shall not trip if the AC power supply to the auxiliary systems is lost for up to 600 milliseconds.

CC.6.4.15.2 Each Generating Module or Energy Storage Unit is required to operate through System fault and disturbance which in this Grid Code is termed as fault ride through capability. The fault ride through capability requirements on Generating Modules presented in the figures below:

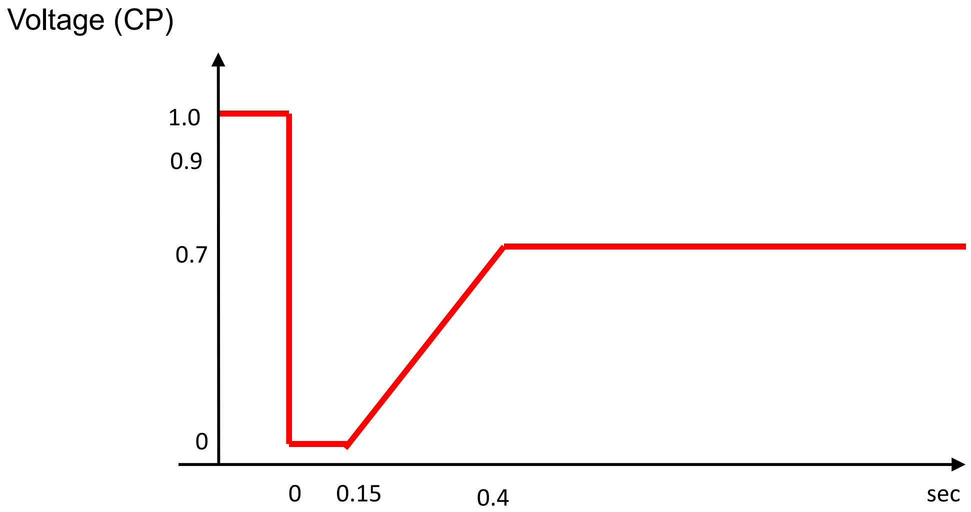


Figure 5 - Type B Synchronous Generating Modules, Fault Ride Through

For short circuit faults on the Grid System each Generating Module, Power Park Module or Energy Storage Unit and any constituent of it shall withstand fault and fault clearance, both dynamic voltage excursion and voltage restoration in the Grid System as described below and remain transiently stable and connected to the System without tripping. After fault has been cleared, Active Power output shall be restored immediately to at least 90% of the level available before the fault. Once the Active Power output has been restored to the required level, Active Power oscillations shall be acceptable provided that the oscillations are adequately damped.

Fault Ride Through requirements for the Power Park Modules and the Energy Storage Units is presented in the figure below:

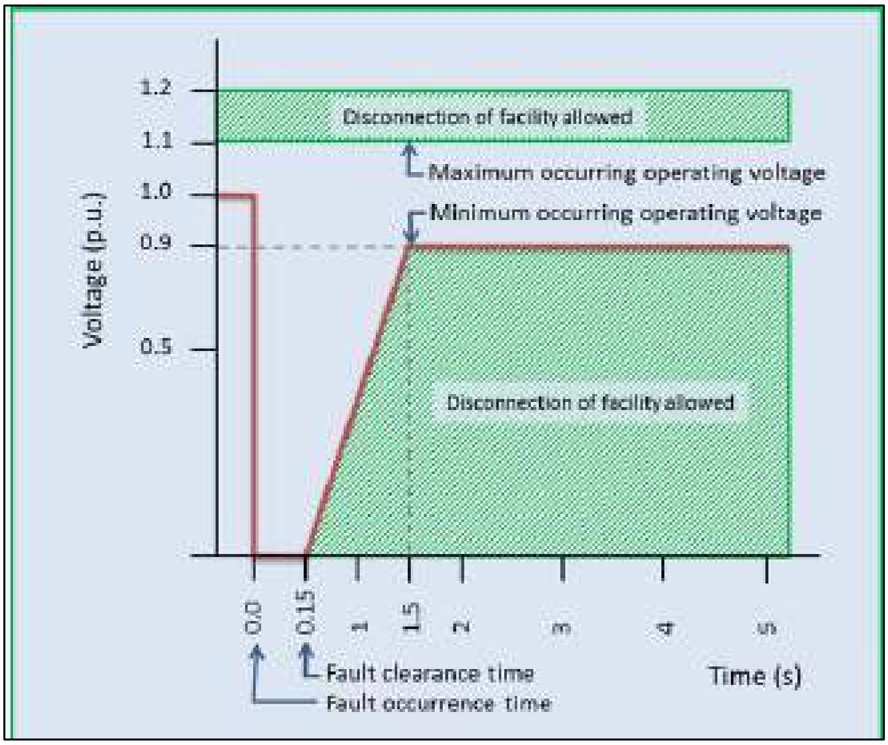


Figure 6 - Power Park Modules and Energy Storage Units Fault Ride Through Requirements

It is reminded that the curves for the Synchronous Generating Modules and for the Power Park Modules and Energy Storage Units present the minimum requirement and not design criteria. For avoidance of doubt the curves present the areas where the Generating Module **May Trip and not where it Must Trip.**

In addition to the above requirements, voltage dips on the Grid System that remains within the given fault ride through curves and greater than 300ms in duration, each Generating Module or Energy Storage Unit and / or any constituent of it shall —

(a) remain transiently stable and connected to the System without tripping of any Generating Module or Energy Storage Unit and / or any constituent of, for balanced voltage dips and associated durations on the Grid System (which could be at the Connection Point); and/or

(b) provide Active Power output at the Connection Point during voltage dips on the Grid System at least in proportion to the retained balanced voltage at the Connection Point (except when there has been a reduction in the Intermittent Power Source) and shall generate reactive current (where the voltage at the Connection Point is outside the limits specified in CC6.2.4.1) without exceeding the transient rating limits of the Generating and any constituent of it. The quantum of reactive current shall be based on settable FRT droop and P/Q priority values.

CC.6.4.16 Generator and Power Station Monitoring Equipment

CC.6.4.16.1 The Grid Owner, Power Station or relevant Users specified by GSO shall install specific monitoring equipment at the substation and or within the Power Station where the Power Station is located. The specification and the specific plant parameters of this equipment enabling the Grid Owner and the GSO to monitor the dynamic behaviour of the plant during normal and disturbed system operation shall be provided in the relevant Agreement and the installation shall be in accordance with the approved Grid Owner's protection relaying scheme. The monitoring equipment installed shall be capable of recording both slow and fast sampling events with the appropriate resolution levels to enable meaningful and appropriate post event analysis to be carried out.

CC.6.4.16.2 The GSO shall make the recordings from such equipment available to any joint investigation of system incidents and investigations of incidents where unexpected Generator behaviour has been observed.

CC.6.4.17 Special Provisions for Hydro and Induction Generators

CC.6.4.17.1 Hydro Generating Unit, which have the ability to operate as a synchronous condenser, may be required to provide synchronous condenser mode of operation by the GSO, as included in the relevant Agreement.

CC.6.4.17.2 If the Power Station includes induction type generator(s), the Generator shall provide power factor correction means so that the Power Station will neither normally demand reactive power from, nor supply reactive power to, the Grid System. The power factor correction equipment may be installed by the Generator at his Plant as required by the Grid Owner and the GSO. The Grid Owner and the GSO have the right to review the Generator's power factor correction plant and to require modifications to or additions as needed, in the Grid Owner and the GSO's opinion, to maintain the Grid System's integrity.

CC.6.4.18 Requirements to conduct test.

CC.6.4.18.1 Generators shall be responsible for carrying out tests to prove compliance on the requirements stated in this CC.

CC.6.4.18.2 All tests must at least meet the requirements stated in CC8.

CC.6.5 General Requirements for Distributors, Network Operators and Grid Connected Customers

CC.6.5.1 Introduction

CC.6.5.1.1 This part of the Grid Code describes the technical and design criteria and performance requirements for Distributors, Grid Connected Customers, and Network Operators.

CC.6.5.2 Neutral Earthing

CC.6.5.2.1 At nominal System voltages of 132kV and above, the higher voltage windings of three phase transformers and transformer banks connected to the Grid System must be star connected with the star point suitable for connection to earth. The Earthing and the lower voltage winding arrangement shall be such as to ensure that the Earth Fault Factor requirement of paragraph CC6.3.2.2 will be met on the Grid System at nominal System voltages of 132kV and above.

CC.6.5.3 Under-Frequency Load Shedding Relays

CC.6.5.3.1 As explained under OC4, each Distributor, Grid Connected Customer, and Network Operator, shall make arrangements that will facilitate automatic low Frequency disconnection of Demand (based on Annual Peak Demand Condition). The relevant Agreement will specify the manner in which Demand subject to low Frequency disconnection will be split into discrete MW blocks with associated under-frequency Load Shedding Relay settings. Typical technical requirements relating to under-frequency Load Shedding Relays as per approved Grid Owner’s protection relaying scheme. The Grid Owner, in consultation with the GSO shall specify the detailed characteristics of the under-frequency Load Shedding Relays to be utilised for implementing the automatic low Frequency disconnection of Demand in accordance with the Grid System Requirement.

CC.6.6 Communications for Facilities, Plant and Apparatus

CC.6.6.1 Introduction

CC.6.6.1.1 In order to ensure control of the Grid System, telecommunications between Users and the GSO must, if required by the GSO, be established in accordance with the requirements set down below.

CC.6.6.2 Control Telephony

CC.6.6.2.1 Control Telephony is the method by which a User's Responsible Engineer/Operator and a GSO Grid Operator speak to one another for the purposes of control of the Power System in both normal and emergency operating conditions. Control Telephony provides secure point to point telephony for routine Control Calls, priority Control Calls and emergency Control Calls.

CC.6.6.2.2 Supervisory tones indicate to the calling and receiving parties dial, engaged, ringing, secondary engaged (signifying that priority may be exercised) and priority disconnect tones. The calls made and received over Control Telephony are recorded and kept for 3 years. The records can be used for commercial and operation reasons, as much as needed.

CC.6.6.2.3 Where the GSO requires Control Telephony, Users are required to use the Control Telephony with the GSO in respect of all Connection Points with the Grid System and in respect of all Embedded Power Station. The User will install Control Telephony to the GSO's specification where the User's telephony equipment is not capable of providing the required facilities or is otherwise incompatible with the GSO Control Telephony. Details of and relating to the Control Telephony required are contained in the relevant Agreement.

CC.6.6.2.4 Detailed information on Control Telephony facilities and suitable equipment required for individual User applications will be provided by the GSO upon request.

CC.6.6.3 SCADA

CC.6.6.3.1 The User shall provide Supervisory Control and Data Acquisition (SCADA) outstation interface equipment. The User shall provide information about its substation such as voltage, current, Frequency, Active Power and Reactive Power measurements and circuit breaker, disconnector status indications; information from protections and alarms to the SCADA outstation interface equipment as required by the GSO. The User shall be able to implement supervisory control function. This covers the capability to accept set points and command signals from Control Centre's SCADA, to echo back the signals and to implement the request to set points and command as required by GSO. The User shall be able to implement remote control switching and change its level of operation according from electronic signal sent from Control Centre's SCADA.

CC.6.6.3.2 For the avoidance of doubt, for Active Power and Reactive Power measurements, circuit breaker and disconnector status indications, data regarding reactive limit, level of primary and secondary reserves (where requested by the GSO) from all Power Stations, the outputs and status indications must each be provided to the GSO on an individual Generating Module or Energy Storage Unit basis. In addition, where identified by GSO, Active Power and Reactive Power measurements from unit and/or station transformers must be provided.

CC.6.6.3.3 In the case of a Power Park Module an additional energy input signal (e.g., solar radiation level) may be specified in the relevant Agreement and for being in accordance with Good Industry Practice and approved by the GSO. The signal may be used to establish the level of energy input from the Intermittent Power Source for monitoring pursuant to CC6.7.1 and Ancillary Services and will, in the case of a solar power park, be used to provide the GSO with advanced warning of solar power shutdown.

CC.6.6.3.4 Each Aggregator must be equipped with a Control Centre, in order to get information from its own customers for knowing their consumption or production and to measure their variation of consumption or production in case of the activation of the Ancillary Service. Each Aggregator must be able to communicate this information to the GSO.

CC.6.6.3.5 All Users must appoint an employee acting as a person in charge of the condition, availability and reliability of the outstation interface equipment.

CC.6.6.4 Aggregator Forecast Data

CC.6.6.4.1 Each Aggregator must communicate the forecast of the consumption or production he can provide daily and weekly on an hourly basis to the GSO for real time information and the SB via web services or as determined and agreed by the GSO and the SB.

CC.6.6.4.2 In addition, the GSO and the SB can request additional information from the Aggregator like monthly forecast or for monitoring the effectiveness of the Ancillary Service response or for analysist in case of event on the Grid System.

CC.6.6.5 Data Entry Terminals

CC.6.6.5.1 The User shall provide and accommodate Data Entry Terminals as specified by the GSO, for the purposes of information exchange with the GSO.

CC.6.6.6 Emails and electronic communication

CC.6.6.6.1 Each User shall provide and maintain an email address or other electronic communication means —

(a) in the case of Generators, at the Control Point of each Power Station and at its Control Centre (if any);

(b) in the case of Network Operators, at the Control Centre(s);

(c) in the case of Grid Connected Customers at the Control Point;

(d) in the case of Energy Storage Operators, at the Control Point; and

(e) in the case of Aggregator, at its Control Centre.

CC.6.6.6.2 Each User, prior to connection to the System of the User's Plant and Apparatus, shall notify the GSO of its or their telephone number(s), and will notify the GSO of any changes thereafter. Prior to connection to the System of the User's Plant and Apparatus, or submission of an offer for a Demand Reduction Block for which it is responsible, the GSO shall notify each User of the telephone number or email address, or other coordinates needed for electronic communication and will notify any changes thereafter.

CC.6.6.7 Busbar Voltage

CC.6.6.7.1 The Grid Owner shall, subject as provided below, provide each Generator or Energy Storage Operator at each Connection Point, where its Power Station is connected with appropriate voltage signals to enable the Generator or Energy Storage Operator to obtain the necessary information to synchronize its Generating Module or Energy Storage Unit to the Grid System.

CC.6.7 System Monitoring

CC.6.7.1 Monitoring equipment is provided on the Grid System to enable the GSO to monitor the Power System dynamic performance conditions. Where this monitoring equipment requires generator parameter signals from the User, the GSO will inform the User and they will be provided by the User with both the timing of the installation of the equipment for receiving such signals and its exact position being agreed pursuant to the terms of the relevant Agreement. The Grid Owner shall provide the appropriate voltage signals to the Generator for enabling the synchronization of the Generating modules.

CC.7 Site Related Conditions

CC.7.1 General

CC.7.1.1 In the absence of Agreement between the parties to the contrary, construction, commissioning, control, operation and maintenance responsibilities follow ownership.

CC.7.2 Responsibilities for Safety

CC.7.2.1 Any User entering and working on its Plant and/or Apparatus on a Grid Owner’s Site will work to the Grid Owner Safety Rules.

CC.7.2.2 The Grid Owner entering and working on its Plant and/or Apparatus on a User Site will work to the User's Safety Rules.

CC.7.2.3 A User may, with a minimum of six (6) weeks’ notice, apply to the Grid Owner for permission to work according to that Users own Safety Rules when working on its Plant and/or Apparatus on the Grid Owner Sites rather than that of the Grid Owner. If the Grid Owner is of the opinion that the User's Safety Rules provide for a level of safety commensurate with that of the Grid Owner Safety Rules, it will notify the User, in writing, that, with effect from the date requested by the User, the User may use its own Safety Rules when working on its Plant and/or Apparatus on the Grid Owner’s sites. Until receipt of such written approval from the Grid Owner, the User will continue to use the Grid Owner Safety Rules.

CC.7.2.4 The Grid Owner may, with a minimum of six (6) weeks' notice, apply to a User for permission to work according to Safety Rules of the Grid Owner when working on its Plant and/or Apparatus on that User's Sites, rather than the User's Safety Rules. If the User is of the opinion that Safety Rules of the Grid Owner provide for a level of safety commensurate with that of User's Safety Rules, it will notify the Grid Owner, in writing, that with effect from the date requested by the Grid Owner, the Grid Owner may use its own Safety Rules when working on its Plant and/or Apparatus on that User's Sites. Until receipt of such written approval from the User, the Grid Owner will continue to use the User's Safety Rules.

CC.7.2.5 If the Grid Owner gives its approval for the User's Safety Rules to apply when working on its Plant and/or Apparatus, that does not imply that the User's Safety Rules will apply to entering the Grid Owner's Site and access to the User's Plant and/or Apparatus on that the Grid Owner Site. Bearing in mind the Grid Owner's responsibility for the whole Site, entry and access will always be in accordance with the Grid Owner's site access procedures.

CC.7.2.6 If a User gives its approval for the Grid Owner Safety Rules to apply when working on its Plant and/or Apparatus, that does not imply that the Grid Owner Safety Rules will apply to entering the User Site and access to the Grid Owner's Plant and/or Apparatus on that User Site. Bearing in mind a User's responsibility for the whole User Site, entry and access will always be in accordance with the User's site access procedures.

CC.7.2.7 Users and the Grid Owner shall notify each other of any Safety Rules that apply to the other's staff working on its Connection Sites.

CC.7.2.8 Each Site Responsibility Schedule must have recorded on it the Safety Rules which apply to each item of Plant and/or Apparatus.

CC.7.3 Site Responsibility Schedules

CC.7.3.1 In order to inform site operational staff and the GSO Grid Operators of agreed responsibilities for Plant and/or Apparatus at the operational interface, a Site Responsibility Schedule shall be produced for the Grid Owner and Users with whom they interface.

CC.7.3.2 The format, principles and basic procedure to be used in the preparation of Site Responsibility Schedules are set down in Appendix 1.

CC.7.4 Operation and Gas Zone Diagrams

CC.7.4.1 Operation Diagrams

CC.7.4.1.1 An Operation Diagram shall be prepared for each Connection Site at which a Connection Point exists using, where appropriate, the graphical symbols shown in CCA.1.3 Appendix 2 Part 1A. Users should also note that the provisions of OC11 apply in certain circumstances.

CC.7.4.1.2 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 OC9. At those Connection Sites where gas-insulated metal enclosed switchgear and/or other gas-insulated HV Apparatus is installed, those items must be depicted within an area delineated by a chain dotted line which intersects gas-zone boundaries. The nomenclature used shall conform to that used on the relevant Connection 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.

CC.7.4.1.3 A non-exhaustive guide to the types of HV Apparatus to be shown in the Operation Diagram is shown in CCA2.2 of Appendix 2, together with certain basic principles to be followed unless equivalent principles are approved by the GSO.

CC.7.4.2 Gas Zone Diagrams

CC.7.4.2.1 A Gas Zone Diagram shall be prepared for each Connection Site at which a Connection Point exists where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised. They shall use, where appropriate, the graphical symbols shown in CCA1.3 Appendix 2 Part 1B.

CC.7.4.2.2 The nomenclature used shall conform to that used in the relevant Connection Site and circuit.

CC.7.4.2.3 The basic principles set out in Part 2 of Appendix 2 shall be followed in the preparation of Gas Zone Diagrams unless equivalent principles are approved by the Grid Owner.

CC.7.4.3 Preparation of Operation and Gas Zone Diagrams for User's Sites

CC.7.4.3.1 In the case of a User Site, the User shall prepare and submit to the GSO and the Grid Owner, an Operation Diagram for all HV Apparatus on the User side of the Connection Point and the Grid Owner shall provide the User with an Operation Diagram for all HV Apparatus on the Grid Owner side of the Connection Point, in accordance with the timing requirements of the relevant Agreement prior to the Completion Date under the relevant Agreement.

CC.7.4.3.2 The User will then prepare, produce and distribute, using the information submitted on the User's Operation Diagram and the Grid Owner Operation Diagram, a composite Operation Diagram for the complete Connection Site, also in accordance with the timing requirements of the relevant Agreement.

CC.7.4.3.3 The provisions of CC7.4.3.1 and CC7.4.3.2 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised.

CC.7.4.4 Preparation of Operation and Gas Zone Diagrams for Grid Owner's Sites

CC.7.4.4.1 In the case of a Grid Owner's Site, the User shall prepare and submit to the GSO and the Grid Owner an Operation Diagram for all HV Apparatus on the User side of the Connection Point, in accordance with the timing requirements of the relevant Agreement.

CC.7.4.4.2 The Grid Owner will then prepare, produce and distribute, using the information submitted on the User's Operation Diagram, a composite Operation Diagram for the complete Connection Site, also in accordance with the timing requirements of the relevant Agreement.

CC.7.4.4.3 The provisions of CC7.4.4.1 and CC7.4.4.2 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised.

CC.7.4.5 Changes to Operation and Gas Zone Diagrams

CC.7.4.5.1 When the Grid Owner has decided that they wish to install new HV Apparatus or they wish to change the existing numbering or nomenclature of their HV Apparatus at their own Site, one month prior to the installation or change, they must send to each User a revised Operation Diagram of that Site, incorporating the new HV Apparatus to be installed and its numbering and nomenclature, as well as the changes. However, if the Grid Owner wishes would cause a Modification under the relevant Agreement, provisions from said Agreement relating to timing apply OC11 is also relevant to certain Apparatus.

CC.7.4.5.2 When a User 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 its User Site, the User will (unless it gives rise to a Modification under the relevant Agreement, in which case the provisions of the relevant Agreement as to the timing apply) one (1) month prior to the installation or change, send to the Grid Owner, a revised Operation Diagram of that User Site incorporating the new User’s HV Apparatus to be installed and its numbering and nomenclature or the changes as the case may be. OC11 is also relevant to certain Apparatus.

CC.7.4.5.3 The provisions of CC7.4.5.1 and CC7.4.5.2 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus are installed.

CC.7.4.6 Validity

CC.7.4.6.1 The composite Operation Diagram prepared by the Grid Owner or the User, as the case may be, will be the definitive Operation Diagram for all operational and planning activities associated with the Connection Site. If a dispute arises related to the accuracy of the composite Operation Diagram, a meeting shall be held at the Connection Site, as soon as reasonably practicable, between the Grid Owner and the User, to endeavour to resolve the matters in dispute.

CC.7.4.6.2 An equivalent rule shall apply for Gas Zone Diagrams where they exist for a Connection Site.

CC.7.5 Site Common Drawings

CC.7.5.1 Introduction

CC.7.5.1.1 Site Common Drawings will be prepared for each Connection Site and will include Connection Site layout drawings, electrical layout drawings, common Protection/control drawings and common services drawings.

CC.7.5.2 Preparation of Site Common Drawings for User Site and Grid Owner Site

CC.7.5.2.1 In the case of a User Site, the Grid Owner shall prepare and submit to the User, Site Common Drawings for his side of the Connection Point in accordance with the timing requirements of the relevant Agreement.

CC.7.5.2.2 Based on the above, the User shall then prepare, produce and distribute Site Common Drawings for the complete Connection Site in accordance with the timing requirements of the relevant Agreement.

CC.7.5.2.3 In the case of a Grid Owner Site, the User will prepare and submit to the Grid Owner, Site Common Drawings for the User side of the Connection Point in accordance with the timing requirements of the relevant Agreement.

CC.7.5.2.4 Based on this, the Grid Owner shall then prepare, produce and distribute Site Common Drawings for the complete Connection Site in accordance with the timing requirements of the relevant Agreement.

CC.7.5.3 Changes to Site Common Drawings

CC.7.5.3.1 When a User becomes aware that it is necessary to change any aspect of the Site Common Drawings at a Connection Site it will —

(a) if it is a User Site, as soon as reasonably practicable, prepare, produce and distribute revised Site Common Drawings for the complete Connection Site; and

(b) if it is the Grid Owner Site, as soon as reasonably practicable, prepare and submit to the Grid Owner, revised Site Common Drawings for the User side of the Connection Point. Based on this. The Grid Owner will as soon as reasonably practicable, prepare, produce and distribute, revised Site Common Drawings for the complete Connection Site.

In either case, if in the User's reasonable opinion, the change can be dealt with by it notifying the Grid Owner in writing of the change and for each party to amend its copy of the Site Common Drawings (or where there is only one set, for the party holding that set to amend it), then it shall therefore notify the parties and the parties can amend it. If the change gives rise to a Modification under the relevant Agreement, the provisions of the relevant Agreement as to timing will apply.

CC.7.5.3.2 When the Grid Owner becomes aware that it is necessary to change any aspect of the Site Common Drawings at a Connection Site it will:

(a) if it is the Grid Owner Site, as soon as reasonably practicable, prepare, produce and distribute revised Site Common Drawings for the complete Connection Site;

(b) if it is a User Site, as soon as reasonably practicable, prepare and submit to the User, revised Site Common Drawings for the Grid Owner side of the Connection Point. Based on this, the User will as soon as reasonably

practicable, prepare, produce and distribute, revised Site Common Drawings for the complete Connection Site.

In either case, if in the Grid Owner's reasonable opinion, the change can be dealt with by it notifying the User in writing of the change and for each party to amend its copy of the Site Common Drawings (or where there is only one set, for the party holding that set to amend it), then it shall so notify, and each party shall so amend. If the change gives rise to a Modification under the relevant Agreement, the provisions of the relevant Agreement relating to timing will apply.

CC.7.5.4 Validity

CC.7.5.4.1 The Site Common Drawings for the complete Connection Site prepared by the User or the Grid Owner, will be the definitive Site Common Drawings for all operational and planning activities associated with the Connection Site. If a dispute arises concerning the accuracy of the Site Common Drawings, a meeting shall be held at the Site, as soon as reasonably practicable, between the Grid Owner and the User, to endeavour to resolve the matters in dispute.

CC.7.6 Access

CC.7.6.1 The provisions relating to access to the Grid Owner’s Sites by Users, and to User’s Sites by the Grid Owner, is set out in each relevant Agreement.

CC.7.6.2 In addition to those provisions, where a Grid Owner Site contains exposed HV conductors, unaccompanied access will only be granted to individuals holding an Authority for Access issued by the Grid Owner.

CC.7.6.3 The procedure for applying for an Authority for Access is contained in the relevant Agreement.

CC.7.6.4 Arrangements will be provided so that the Grid Owner and the GSO on giving prior notice and reasons for the visit may have access to the Generator's facilities and metering equipment at any time.

CC.7.7 Maintenance Standards

CC.7.7.1 It is a requirement that all User's Plant and Apparatus on the Grid Owner Sites are maintained so they can adequately fulfil their purpose and to ensure that they do not pose a threat to the safety of any of the Grid Owner's Plant or Apparatus or personnel on the Grid Owner Site. The Grid Owner will have the right to inspect the test results and maintenance records relating to such Plant and Apparatus at any time.

CC.7.7.2 It is a requirement that all the Grid Owner's Plant and Apparatus on User's Sites is maintained adequately for the purposes for which it is intended and to ensure that it does not pose a threat to the safety of any of the User's Plant, Apparatus or personnel on the User Site. Users will have the right to inspect the test results and maintenance records relating to such Plant and Apparatus, at any time.

CC.7.8 Site Operational Procedures

CC.7.8.1 The Grid Owner and Users with an interface with the Grid Owner must make staff available 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 and Apparatus connected to the Power System.

CC.8 Commissioning Tests

CC.8.1 Introduction

CC.8.1.1 The following specifies the procedures to be followed by the GSO, the Grid Owner, the Single Buyer and the Users in coordinating and carrying out tests to ensure compliance by Users covering all parts of the Connection Codes, Scheduling and

Dispatch Parameters, Ancillary Service Duties including but not limited to response to frequency, reactive capability, unit start capability and Black Start capability.

CC.8.1.2 The GSO and the Single Buyer are responsible for facilitating and coordinating the required testing. The User is responsible for carrying out the test in accordance with the relevant Agreement and or specifications issued by the GSO and the Single Buyer.

CC.8.2 Objectives

CC.8.2.1 The objectives are:

(a) to enable the GSO and the Single Buyer to carry out, facilitate and coordinate testing the Grid System or User's System at the Grid Supply Point to ensure compliance, in accordance to any relevant Agreement and GSO’s interfacing and testing guidelines, which include automated functions;

(b) to establish whether Users comply with the Connection Code;

(c) to establish whether Generators or Energy Storage Operators can provide those Ancillary Services which they are either required or have agreed to provide under relevant Agreement and GSO‘s interfacing and testing guidelines, which include automated functions.

CC.8.3 Scope

CC.8.3.1 The commissioning tests procedure applies to the GSO and the Single Buyer and the following Users:

(a) Generators;

(b) Network Operators;

(c) The Grid Owner;

(d) Distributors;

(e) Grid Connected Customers;

(f) Energy Storage Operators.

CC.8.4 Procedure for Testing

CC.8.4.1 General

CC.8.4.1.1 This section describes the activities involved in commissioning tests as follows:

(a) Commissioning and testing programs: The Users shall prepare and submit the commissioning and testing programs. The GSO is responsible for reviewing, facilitating and coordinating the required testing and monitoring. If required, the GSO have the option to request the participation of representatives from Single Buyer and the Grid Owner in reviewing the commissioning and testing programs.

(b) Test procedure: The Users shall prepare and submit the test procedures, which shall include name, description and purpose of each test, test configurations/schematics, test codes and standards used for each test and acceptance (pass/fail) criteria for each test. The test procedures shall be approved by the GSO.

(c) Submission of documents: The Users shall submit documents of the approved commissioning, test procedures and the test results in softcopy. A softcopy shall also be provided in a form of electronic data storage device of the related files.

CC.8.4.1.2 For tests which are required under the Grid Code, relevant Agreements, testing guidelines and Licence Standards, the GSO will consider such for tests which are required under the Grid Code, relevant Agreements, testing guidelines and Licence Standards, the GSO will consider such will always have the right to witness the tests and the notice of the tests by the User shall be at least one (1) week.

CC.8.4.1.3 Any testing to be carried out is subject to Grid System conditions prevailing on the day.

CC.8.4.2 Reactive Power Tests

CC.8.4.2.1 Reactive Power tests are be conducted to demonstrate that the relevant Generating Module or Energy Storage Unite meets the Reactive Power capability registered with the GSO and the Single Buyer under the SDC which shall meet the requirements set out in the CC.

CC.8.4.2.2 The procedure for carrying out Reactive Power tests will be specified by the GSO, and the test details and the procedures shall be agreed between the GSO and the relevant Generator or Energy Storage Operator.

CC.8.4.2.3 A Reactive Power test will be initiated by the issue of Dispatch instructions under SDC2. During the Reactive Power test, the voltage at the Grid Supply Point for the relevant Generating Module or Energy Storage Unit will be maintained by the Generator at the voltage required by SDC2 through adjustment of Reactive Power on the remaining Generating Modules, if necessary.

CC.8.4.2.4 The Reactive Power performance of the Generating Module or Energy Storage Unit will be recorded by a method to be determined by the GSO, and the Generating Module will pass the test if it is within ±2.5 % of the capability registered under the PC, which in turn, shall meet the requirements set out in CC (with due account being taken of any conditions on the Grid System that may affect the test results). The relevant Generator must, if requested, demonstrate, to the reasonable satisfaction of the GSO, the reliability and accuracy of the equipment used in recording the performance.

CC.8.4.3 Frequency Response Tests

CC.8.4.3.1 Testing of frequency response performance will be carried out, to test compliance with Dispatch instructions for operation in Frequency Sensitive Mode under the SDC and in compliance with the PC and CC.

CC.8.4.3.2 The procedure for carrying out Frequency Response Tests will be specified by the GSO. The test details and procedures shall be agreed between the GSO and the relevant Generator or Energy Storage Operator.

CC.8.4.3.3 The frequency response performance of the Generating Module or Energy Storage Unit will be recorded by the GSO from voltage and current signals provided by the Generator for each Generating unit. If monitoring at site is undertaken, the performance of the Generating Module as well as Grid System Frequency and other parameters deemed necessary by the GSO will be recorded as appropriate and the Generating Module will pass the test if:

(a) monitoring of the Primary Response and or Secondary Response and or High Frequency Response to frequency change on the Grid System has been carried out, and the measured response in MW/Hz is within ± 2.5 % of the level of response specified in the parameters in the CC or in other relevant Agreements for that Generating Module or Energy Storage Unit;

(b) measurements of the governor pilot oil/valve position have been requested, such measurements indicate that the governor parameters are within the criteria as determined by the GSO;

(c) monitoring of the High Frequency Response to frequency change on the Grid System has been carried out, and the measured response is within the requirements of the SDC for Frequency Sensitive Response.

CC.8.4.3.4 The relevant Generator or Energy Storage Operator must, if requested, demonstrate to the GSO with reasonable satisfaction the reliability of any equipment used in the test.

CC.8.4.4 Black Start Tests

CC.8.4.4.1 The GSO may require a Generator with a Black Start Power Station to carry out a test (“Black Start Test”) on a Generating Module in a Black Start Power Station either while the Black Start Power Station remains connected to an external alternating current electrical supply ("Black Start Generating Unit Test"), or while the Black Start Power Station is disconnected from all external alternating current supplies ("Black Start Power Station Test”) in order to demonstrate that a Black Start Power Station has a Black Start capability.

CC.8.4.4.2 Where the GSO requires a Generator with a Black Start Power Station to carry out a Black Start Generating Unit Test, the GSO shall not require the Black Start Test to be carried out on more than one Generating Module at that Black Start Power Station at the same time, and would not, in the absence of exceptional circumstances, expect any of the other Generating Modules at the Black Start Power Station to be directly affected by the Black Start Generating Unit Test.

CC.8.4.4.3 All Black Start Tests shall be carried out at the time specified by the GSO and shall be undertaken in a manner approved by the GSO.

CC.8.4.4.4 There are two types of Black Start Tests as follows:

(a) Black Start Generating Unit Test;

(b) Black Start Power Station Test.

CC.8.4.4.5 The procedure for carrying out Black Start Tests will be specified by the GSO, and the test details and procedures shall be agreed between the GSO and the relevant Generator.

CC.8.4.4.6 Black Start Generating Unit Test - Where local conditions require variations in this procedure the Generator shall submit alternative proposals, in writing, for prior approval of the GSO. The following procedure shall, so far as practicable, be carried out in the following sequence for Black Start Generating Unit Tests:

(a) The relevant Black Start Generating Unit ("BSGU") shall be Synchronized and Loaded;

(b) All the auxiliary gas turbines and or auxiliary diesel engines and or auxiliary hydro generator in the Black Start Power Station in which that BSGU is situated, shall be shut down;

(c) The BSGU shall be de-Loaded and de-Synchronized and all alternating current electrical supplies to its auxiliaries shall be disconnected;

(d) The auxiliary gas turbine or auxiliary diesel engine to the relevant BSGU shall be started and shall re-energise the unit board of the relevant BSGU;

(e) The auxiliaries of the relevant BSGU shall be fed by the auxiliary gas turbine or auxiliary diesel engine or auxiliary hydro-generator, via the BSGU's unit board, to enable the relevant BSGU to return to Synchronous Speed; and

(f) The relevant BSGU shall be Synchronized to the Grid System but not Loaded, unless the appropriate instruction has been given by the GSO under SDC2.

CC.8.4.5 House Load Test

CC.8.4.5.1 House Load Test of the Generating Unit shall be carried out during the commissioning tests. The Generating Unit must remain in House Load Operation for at least two (2) hours.

CC.8.4.6 Power System Stabiliser (PSS) Test

CC.8.4.6.1 The excitation system of Synchronous Generating Units of Type B shall be equipped with power system stabiliser, (PSS) for damping of power system oscillations on the Grid. Generators shall seek a written advice from the Grid Owner and the GSO, the value of the inter-area oscillation frequencies for which the PSS shall be tuned to.

CC.8.4.6.2 The PSS shall be optimally tuned to damp out local and inter-area oscillation modes with a damping ratio of not less than 5 % while maintaining a sufficient margins of the excitation control system.

CC.8.4.6.3 Generator shall prove conclusively that the PSS for each **Generating Unit** is optimally tuned to damp out the local and the inter-area oscillation modes, by both analytically and via on-site verification tests, including actual line switching test.

CC.8.4.7 Test Reporting Requirements

CC.8.4.7.1 Subject to passing a test, a Preliminary Report of a Compliance Test shall be submitted by the User within twenty-four (24) hours after the completion of the test and a Final Report within seven (7) days by the User unless different periods have been agreed between the GSO, the Single Buyer and the User.

CC.8.4.7.2 The Final Report shall include a description of the Plant and/or Apparatus tested, the date of the test and a description of the System Test carried out, together with the results, conclusions and recommendations.

CC.8.4.7.3 The GSO shall form the Test Approval Committee, which shall comprise of appointed representatives from the Grid Owner, the Single Buyer and the GSO. The committee will be headed by the GSO.

CC.8.4.7.4 The results from each compliance test shall be approved by the Test Approval Committee within ten (10) business days of the last receipt of the final report. The Test Approval Committee approval letter to become a condition precedent prior to the commercial operation as per relevant agreement.

CC.8.5 Failure of Tests

CC.8.5.1 The Users shall provide clarifications to the Test Approval Committee for each failed tests clarifying the causes for such failure or non-compliance and the remedial actions to be taken. The Users shall undertake any necessary rectification of the plant equipment to be capable of meeting the requirements and schedule a re-test. Test Approval Committee may consider to grant approval based on prudent utility practice subject to User’s corrective action to be taken by 180 days and approval of Commission.

CC.8.5.2 The Users shall give advance notification to the Test Approval Committee of the proposed date of re-test, at least three (3) Business Days before the re-test. For User’s tests, which may have a significant impact on the system, the GSO may request the User to reschedule the date of the re-test.

CC.8.5.3 The provisions of the relevant Agreements shall apply for failure of tests thereunder.

CC.8.5.4 In cases the test for which there are no provisions in the relevant Agreements and if a dispute arises relating to the failure, the Test Approval Committee and the relevant parties shall seek to resolve the dispute by discussion.

CC.8.5.5 If the User concerned fails to pass the re-test and a dispute arises from that re-test, either party may use the relevant Agreement dispute resolution procedure. If there is no such provision in the relevant Agreement, then the Grid Code dispute resolution procedure, contained in the General Conditions (GC), for a ruling in relation to the dispute, shall be applied.

<End of the Connection Code Main Text>

Connection Code Appendix 1 – Format, Principles and Basic Procedure to be used for Preparation of Site Responsibility Schedules

CCA.1.1 Principles

CCA.1.1.1 At all Complexes the following Site Responsibility Schedules shall be drawn up using the proforma attached or with variations that may be agreed between the Grid Owner and Users. In the absence of Agreement, the proforma attached will be used —

(a) Schedule of HV Apparatus.

(b) Schedule of Plant, LV/MV Apparatus, services and supplies.

(c) Schedule of telecommunications and measurements Apparatus.

(d) Other than at Generating Modules or Energy Storage Unit and Power Station locations, the schedules referred to in (2) and (3) may be combined.

CCA.1.1.2 Each Site's Responsibility Schedule for a Connection Site shall be prepared by the Grid Owner in consultation with other Users at least two (2) weeks prior to the Completion Date under the relevant Agreement for that Connection Site (which may form part of a Complex). Each User shall, in accordance with the timing requirements of the relevant Agreement, provide information to the Grid Owner to enable it to prepare the Site Responsibility Schedule.

CCA.1.1.3 Each Site's Responsibility Schedule will be subdivided to take account of any separate Connection Sites on that Complex.

CCA.1.1.4 Each Site Responsibility Schedule shall detail for each item of Plant and Apparatus —

(a) Plant/Apparatus ownership;

(b) Site Manager (Controller);

(c) Safety (applicable Safety Rules and Control Person or other responsible person (Safety Coordinator), or such other person who is responsible for safety);

(d) Operations (applicable Operational Procedures and Grid Operator); and

(e) Responsibility to undertake maintenance.

Each Connection Point shall be precisely shown.

CCA.1.1.5 In the case of Site Responsibility Schedules referred to in CCA.1.1.1*(b)* and *(c)*, with the exception of Protection Apparatus and Intertrip Apparatus operation, it will be sufficient to indicate the responsible User or the Grid Owner. In the case of the Site Responsibility Schedule referred to in CCA.1.1.1*(a)* for Protection Apparatus and Interstrip Apparatus, the responsible management unit must be shown in addition to the User or the Grid Owner, as the case may be.

CCA.1.1.6 The HV Apparatus Site Responsibility Schedule for each Connection Site must include lines and cables emanating from the Connection Site.

CCA.1.1.7 Every page of each Site Responsibility Schedule shall bear the date of issue and the issue number.

CCA.1.1.8 When a Site Responsibility Schedule is prepared it shall be sent by the Grid Owner to the Users involved for confirmation of its accuracy.

CCA.1.1.9 The Site Responsibility Schedule shall then be signed on behalf of the Grid Owner by the Area Manager responsible for the area in which the Complex is situated and on behalf of each User involved by its Responsible Manager (see CCA.1.2.4), as written confirmation of its accuracy.

CCA.1.1.10 Once signed, two copies will be distributed by the Grid Owner, not less than two (2) 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.

CCA.1.1.11 The Grid Owner and Users must make the Site Responsibility Schedules readily available to its operational staff at the Complex.

CCA.1.2 Alterations to Existing Site Responsibility Schedules

CCA.1.2.1 Without prejudice to the provisions of CCA.1.2.4, when a User identified on a Site Responsibility Schedule becomes aware that an alteration is necessary, it must inform the Grid Owner immediately and in any event eight (8) weeks prior to any change taking effect (or as soon as possible after becoming aware of it, if less than eight (8) weeks remain when the User becomes aware of the change).

CCA.1.2.2 Where the Grid Owner has been informed of a change by a User, or itself proposes a change, it will prepare a revised Site Responsibility Schedule by not less than six (6) weeks prior to the change taking effect (subject to it having been informed or knowing of the change eight (8) weeks prior to that time) and the procedure set out in CCA.1.1.8 shall be followed with regard to the revised Site Responsibility Schedule.

CCA.1.2.3 The revised Site Responsibility Schedule shall then be signed in accordance with the procedure set out in CCA.1.1.9 and distributed in accordance with the procedure set out in CCA.1.1.10, accompanied by a note indicating where the alteration(s) has/have been made, the new issue number and the date of implementation.

CCA.1.2.4 When a User identified on a Site Responsibility Schedule, or the Grid Owner becomes aware that an alteration to the Site Responsibility Schedule is urgently necessary to reflect, for example, an emergency situation, the User shall notify the Grid Owner, or the Grid Owner shall notify the User, as the case may be, immediately and will discuss:

(a) what change is necessary to the Site Responsibility Schedule; and

(b) whether the Site Responsibility Schedule is to be modified temporarily or permanently before the distribution of the revised Site Responsibility Schedule.

The Grid Owner will prepare a revised Site Responsibility Schedule as soon as possible and in any event within seven (7) days of it being informed of or knowing the necessary alteration. The Site Responsibility Schedule will be confirmed by Users and signed on behalf of the Grid Owner and Users (by the persons referred to in CCA.1.1.9) as soon as possible after it has been prepared and sent to Users for confirmation.

CCA.1.3 Responsible Managers

CCA.1.3.1 Each User shall, prior to the Completion Date under each relevant Agreement, supply to the Grid Owner a list of Managers who have been duly authorized to sign Site Responsibility Schedules on behalf of the User ("Responsible Manager") and the Grid Owner shall, prior to the Completion Date for each relevant Agreement, supply to that User the name of the Area Manager responsible for the area in which the Complex is situated and shall supply to the other User any changes to such list six (6) weeks before the change takes effect where the change is anticipated. Similarly, after the change, the Grid Owner should also note where the change was not anticipated.

Appendix 1 – cont'd

ATTACHMENT TO APPENDIX 1 OF CONNECTION CODE

PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

Area:_________________

Complex: _________________________ Schedule: _________

Connection Site: _________________

Item of Plant/ Apparatus	Plant /Apparatus Owner	Site Manager	Safety		Operations		Party Responsible for Undertaking Statutory Inspections, Fault Investigations & Maintenance	Remarks
			Safety Rules	Control or Other Responsible Person (Safety Coordinator)	Operational Procedures	Control or Other Responsible Engineer		

Page: _______ Issue No: __________ Date: ________________

ATTACHMENT TO APPENDIX 1 OF CONNECTION CODE

PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

Area________________

Complex: ________________________ Schedule : _________

Connection Site: ________________

Item of Plant/ Apparatus	Plant /Apparatus Owner	Site Manager	Safety		Operations		Item of Plant/ Apparatus	Plant /Apparatus Owner
			Safety Rules	Control or Other Responsible Person (Safety Coordinator)	Operational Procedures	Control or Other Responsible Engineer		

NOTES:

SIGNED: __________ NAME: __________ COMPANY: __________ DATE: __________

SIGNED: __________ NAME: __________ COMPANY: __________ DATE: __________

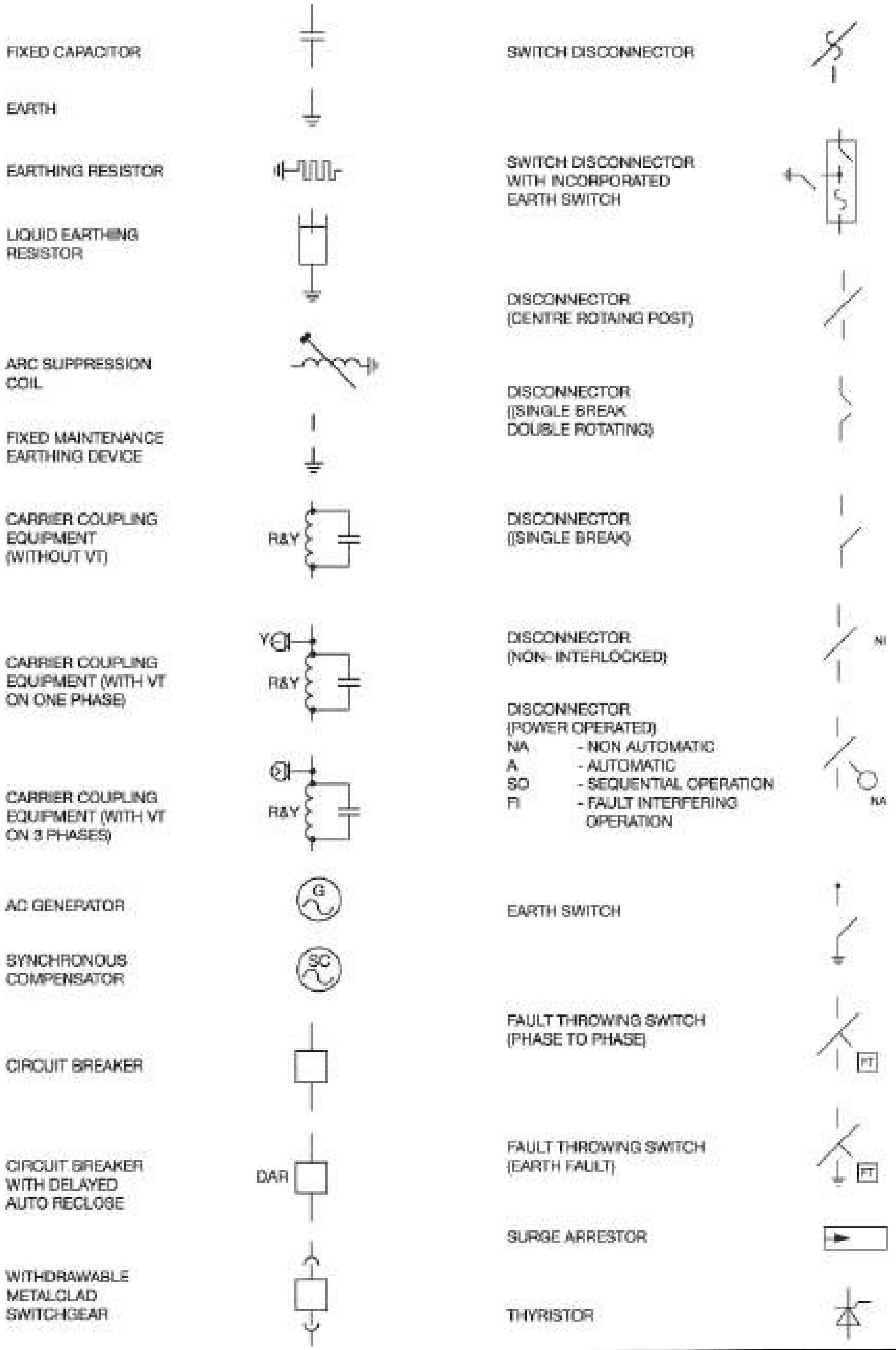
SIGNED: __________ NAME: __________ COMPANY: __________ DATE: __________

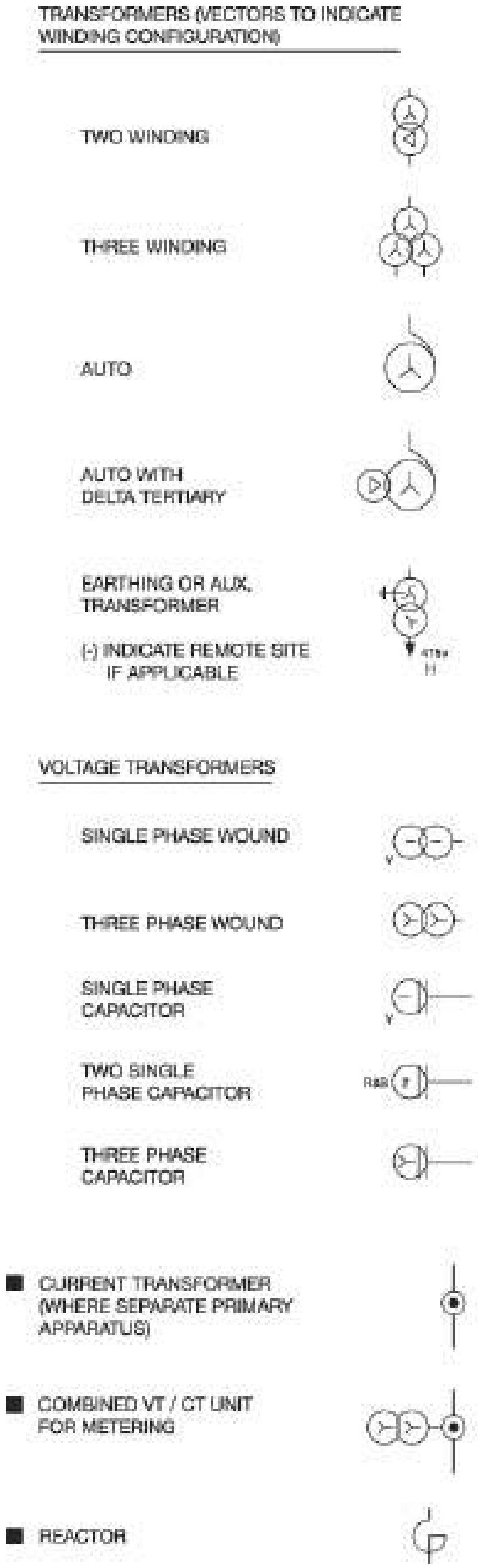
SIGNED: __________ NAME: __________ COMPANY: __________ DATE: __________

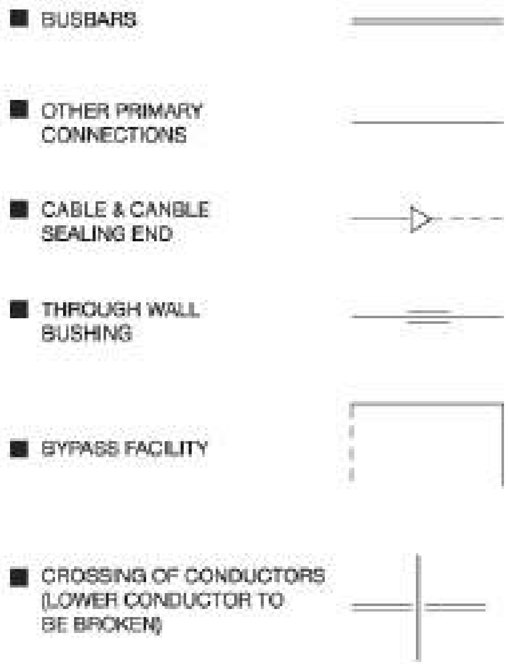
PAGE: _______ ISSUE NO: __________ DATE: ________________

<Connection Code - End of Appendix 1>

Connection Code Appendix 2, Part 1A - Typical Symbols Relating to Operation Diagrams



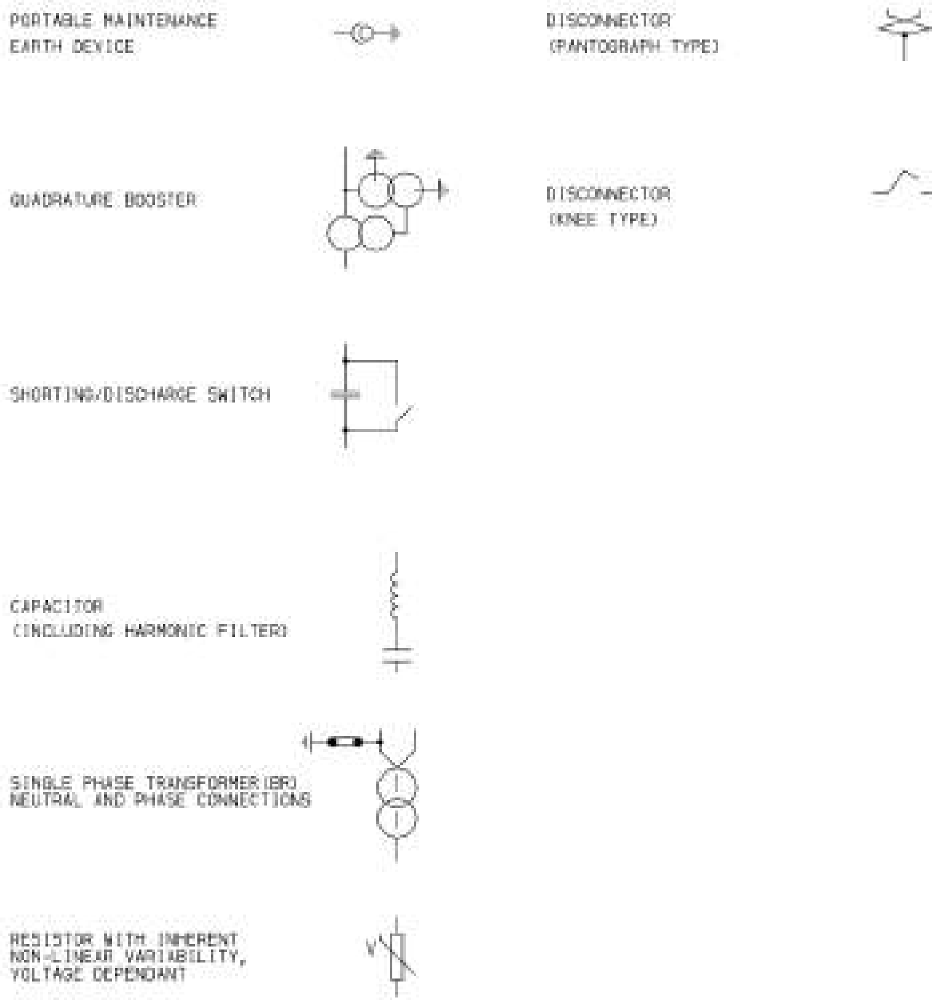




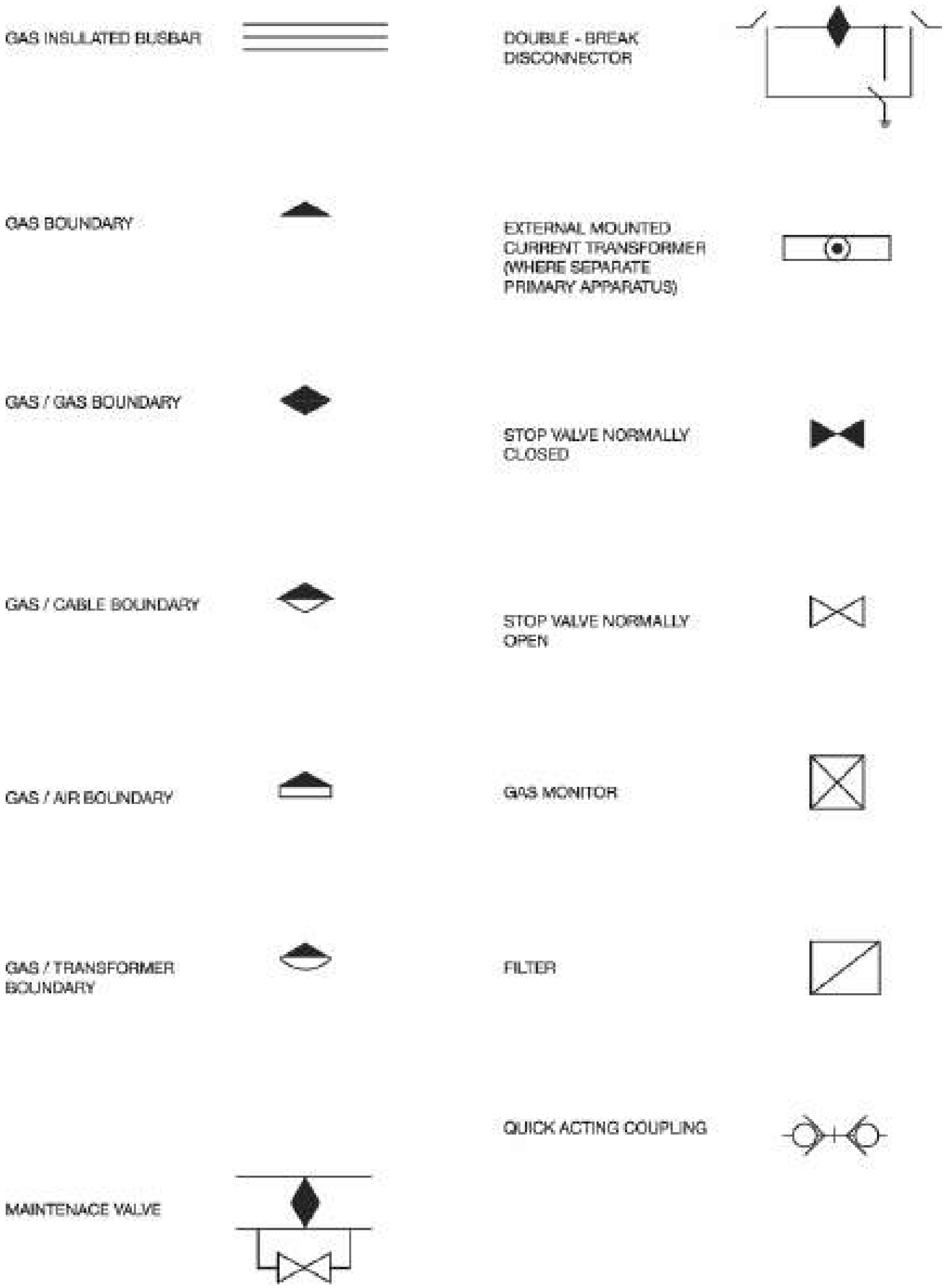
PREFERENTIAL ABBREVIATIONS

AUXILARY TRANSFORMER	Aux T
EARTHING TRANSFORMER	ET
GAS TURBINE	Gas T
GENERATOR TRANSFORMER	Gen T
GRID TRANSFORMER	Gr T
SERIES REACTOR	Ser Reac
SHUNT REACTOR	Sh Reac
STATION TRANSFORMER	Stn T
SUPERGRID TRANSFORMERSGT	
UNIT TRANSFORMER	UT

■ NON STANDARD SYMBOL


PORTABLE MAINTENANCE EARTH DEVICE
DISCONNECTOR (PANTOGRAPH TYPE)
QUADRATURE BOOSTER
DISCONNECTOR (KNEE TYPE)
SHORTING/DISCHARGE SWITCH
CAPACITOR (INCLUDING HARMONIC FILTER)
SINGLE PHASE TRANSFORMER (BR) NEUTRAL AND PHASE CONNECTIONS
RESISTOR WITH INHERENT NON-LINEAR VARIABILITY, VOLTAGE DEPENDANT

Connection Code Appendix 2, Part 1B - Typical Symbols Relating to Gas Zone Diagrams



Connection Code Appendix 2, Part 2 - Basic Principles and Non-Exhaustive List of Apparatus to be Included in Operation Diagrams

CCA.2.1 Basic Principles

CCA.2.1.1 Where practicable, all the HV Apparatus on any Connection Site shall be shown on one Operation Diagram. Provided the clarity of the diagram is not impaired, the layout shall represent as accurately as possible the geographical arrangement of the Connection Site.

CCA.2.1.2 Where more than one Operation Diagram is unavoidable, duplication of identical information on more than one Operation Diagram shall be avoided.

CCA.2.1.3 The Operation Diagram shall show accurately the current status of the Apparatus e.g., whether commissioned or decommissioned. Where decommissioned, the associated switch bay will be labelled "spare bay".

CCA.2.1.4 Provision shall be made on the Operation Diagram for signifying approvals, together with provision for details of revisions and dates.

CCA.2.1.5 Operation Diagrams shall be prepared in A4 format, or another format as agreed with the Grid Owner in consultation with the GSO.

CCA.2.1.6 The Operation Diagram shall normally be drawn as a single line diagram. However, where appropriate, detail which applies to individual phases shall be shown. For example, some HV Apparatus is numbered individually per phase.

CCA.2.2 Non-Exhaustive list of Apparatus to be shown on Operation Diagram

(a) Busbars

(b) Circuit Breakers

(c) Disconnector (Isolator) and Switch Disconnectors (Switching Isolators)

(d) Disconnectors (Isolators) - Automatic Facilities

(e) Bypass Facilities

(f) Earthing Switches

(g) Maintenance Earths

(h) Overhead Line Entries

(i) Overhead Line Traps

(j) Cable and Cable Sealing Ends

(k) Generating Unit

(l) Generator Transformers

(m) Generating Unit Transformers, Station Transformers, including the lower voltage circuit-breakers

(n) Synchronous Compensators

(o) Static Variable Compensators

(p) Capacitors (including Harmonic Filters)

(q) Series or Shunt Reactors (Referred to as "Inductors" at nuclear power station sites)

(r) Supergrid and Grid Transformers

(s) Tertiary Windings

(t) Earthing and Auxiliary Transformers

(u) Three Phase VT's

(v) Single Phase VT & Phase Identity

(w) High Accuracy VT and Phase Identity

(x) Surge Arrestors/Diverters

(y) Neutral Earthing Arrangements on HV Plant

(z) Fault Throwing Devices

(aa) Quadrature Boosters

(bb) Arc Suppression Coils

(cc) Single Phase Transformers (BR) Neutral and Phase Connections

(dd) Current Transformers (where separate plant items)

(ee) Wall Bushings

(ff) Combined VT/CT Units

(gg) Shorting and Discharge Switches

(hh) Thyristor

(ii) Resistor with Inherent Non-Linear Variability, Voltage Dependent

(jj) Gas Zone

< Connection Code - End of Appendix 2>

Connection Code Appendix 3 – Minimum Frequency Response Requirement Profile and Operating Range

CCA.3.1 Scope

CCA.3.1.1 The frequency response capability is defined in terms of Primary Response, Secondary Response and High Frequency Response. This Appendix defines the minimum frequency response requirement profile which shall apply for each Generating Modules or Energy Storage Unit. The Generating Modules or Energy Storage Unit, which could not comply with this requirement (due to ageing for example) could apply for a request to vary.

CCA.3.1.2 The functional definition of the frequency response capability provides appropriate performance criteria relating to the provision of frequency control by means of frequency sensitive generation in addition to the other requirements identified in CC6.4.4.2.

CCA.3.1.3 The minimum frequency response requirement profile is shown diagrammatically in Figure CCA.3.1. This capability profile specifies the minimum required levels of Primary Response, Secondary Response and High Frequency Response throughout the normal plant operating range. The definitions of these frequency response capabilities are illustrated diagrammatically in Figures CCA.3.2 and CCA.3.3.

CCA.3.2 Plant Operating Range

CCA.3.2.1 The upper limit of the operating range is the Registered Capacity of the Generating Module or Energy Storage Unit.

CCA.3.2.2 The Minimum Generation level depends on the different technologies of the Generating Modules, the technical constraints are not the same for hydro, CCGT, Open-Cycle GT, thermal or Power Park Modules. The Generators and Energy Storage Operators must provide their Minimum Generation levels to the Single Buyer, the Grid Owner and the GSO. However, the Minimum Generation must be not more than 50%. Each Generating Module or Energy Storage Unit must be capable of operating satisfactorily down to the Minimum Generating Level as dictated by System operating conditions, although it will not be Dispatched to below its Minimum Generation level. If a Generating Module or Energy Storage Unit is operating below Minimum Generation because of high System Frequency, it should recover adequately to its Minimum Generation level as the System Frequency returns to Target Frequency so that it can provide Primary and Secondary Response from Minimum Generation. For the avoidance of doubt, under normal operating conditions, steady state operation below Minimum Generation is not expected.

CCA.3.2.3 In the event of a Generating Module load rejecting down to no less than its Minimum Generation it should not trip as a result of automatic action as detailed in SDC3.5. If the load rejection is a level less than the Minimum Generation, then it is accepted that the condition might be so severe as to cause it to be disconnected from the System.

CCA.3.2.4 In case of high frequency, the Energy Storage Unit, which are operating as generators synchronized to the Grid System, must be able to reduce its generation to 0 MW, at the request of the GSO Control Centre. In addition, the GSO Control Centre is allowed to request that the Energy Storage Units available start their charging cycle.

CCA.3.3 Minimum Frequency Response Requirement Profile

CCA.3.3.1 Low Frequency response

The percentage response capabilities and loading levels are defined on the basis of the Registered Capacity of the Generating Module of types B.

(a) For low frequency deviations of 0.5Hz or lesser, each Generating Module of this type should response no less than 2% of 0.1Hz change or to the Registered Capacity. For example, if the Frequency deviation is 0.5 Hz, the corresponding minimum frequency response requirement is 10% of the Registered Capacity.

(b) The Frequency response delivered for Frequency deviation of more than 0.5Hz should be not less than the response delivered for a Frequency deviation of 0.5Hz.

CCA.3.3.2 High Frequency Response

The percentage response capabilities and loading levels are defined on the basis of the Registered Capacity of the Generating Module of types B as follows:

(a) For high Frequency deviation of 0.5Hz and lesser, each Generating Module of this type should response no less than 2% of 0.1Hz change or to the minimum generation. For example, if the Frequency deviation is 0.5Hz the corresponding minimum Frequency response requirement is 10% of the Registered Capacity.

(b) The frequency response delivered for Frequency deviations of more than 0.5Hz should be no less than the response delivered for a Frequency deviation of 0.5Hz.

CCA.3.4 Testing of Frequency Response Capability

CCA.3.4.1 The response capabilities, explained in CCA.3.3.1 and CCA.3.3.2, are measured by taking the responses as obtained from some of the dynamic response tests specified by the Grid Owner in consultation with the GSO and carried out by Generators for compliance purposes and to validate the content of relevant Agreement using an injection of a frequency change to the plant control system (i.e., governor and load controller). The injected signal is a linear ramp from zero to 0.5 Hz frequency change over a ten (10) second period, and is sustained at 0.5 Hz frequency change, thereafter, as illustrated diagrammatically in figures CCA.3.1 and CCA.3.2.

CCA.3.4.2 The Primary Response capability (P) of a Generating Module or a Energy Storage Unit of type B is the minimum increase of Active Power output between ten (10) and thirty (30) seconds after the start of the ramp injection as illustrated diagrammatically in Figure CCA.3.1.

CCA.3.4.3 The Secondary Response capability (S) of a Generating Module or Energy Storage Unit of type B is a minimum increase of Active Power output between thirty (30) seconds and thirty (30) minutes after the start of the ramp injection as illustrated diagrammatically in Figure CCA.3.1.

CCA.3.4.4 The High Frequency Response capability (H) of a Generating Module is the decrease in Active Power output provided ten (10) seconds after the start of the ramp injection and sustained thereafter as illustrated diagrammatically in Figure CCA.3.2.

CCA.3.4.5 The High Frequency Response capability (H) of a Power Park Module or an Energy Storage Unit is the decrease in Active Power output immediately after the start of the ramp of the frequency increase and sustained thereafter. In addition to this, the GSO Control Centre may request to the Energy Storage Units to start a charging cycle, depending on their State of Charge.

CCA.3.5 Repeatability of Response

CCA.3.5.1 When a Generating Module or Energy Storage Unit has responded to a significant Frequency disturbance, its response capability must be fully restored as soon as technically possible. Full response capability should be restored no later than twenty (20) minutes after the initial change of System Frequency arising from the Frequency disturbance.

Figure CCA.3.1 - Interpretation of Primary and Secondary Response Values

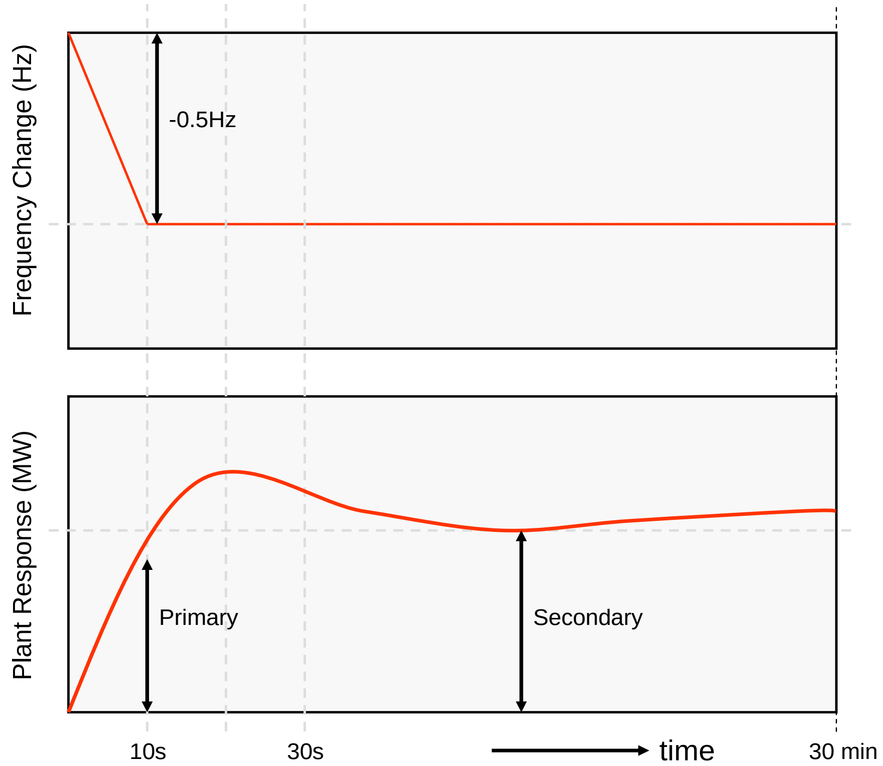
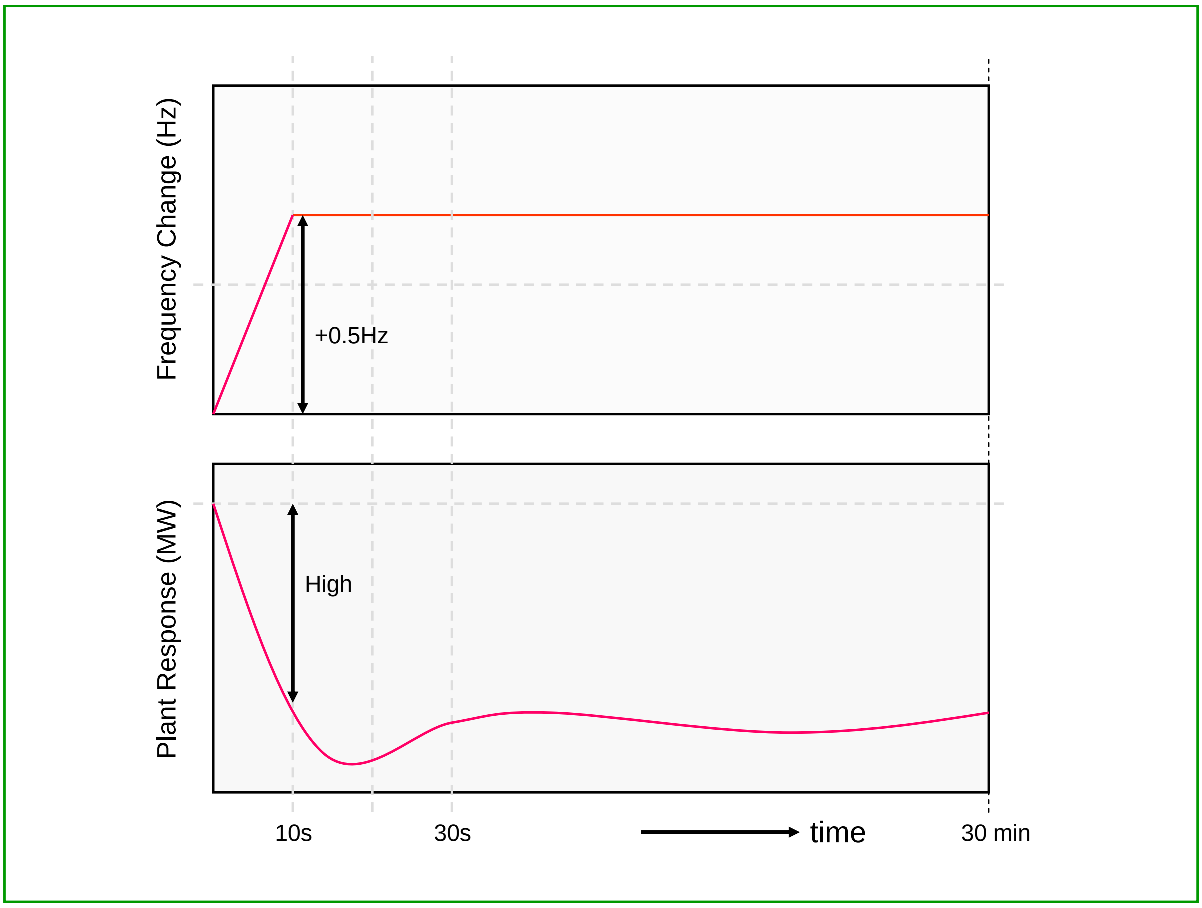


Figure CCA.3.2 - Interpretation of High Frequency Response Values



< Connection Code - End of Appendix 3>

Connection Code Appendix 4 – Typical Technical Requirements of Low Frequency Relays and High Frequency Relays for the Automatic Disconnection of Supply at Low Frequency or High Frequency

CCA.4.1 Frequency Relays

CCA.4.1.1 The Low Frequency Relays to be used shall be in accordance with the requirements of the relevant Agreement. They should have a setting range of 47.0 to 50Hz 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 Low Frequency Relays for automatic installations is given as an indication, without prejudice to the provisions that may be included in a relevant Agreement:

(a)	Frequency settings:	47-50Hz in steps of 0.01Hz
(b)	Measurement period selectable settings:	Within a minimum settings range of 4 to 6 cycles;
(c)	Operating time:	Between 100 and 150ms dependent on measurement period setting.
(d)	Voltage lock-out (under voltage blocking)	Selectable within a range of 50% to 90% of nominal voltage.
(e)	Facility stages:	Minimum of two stages of Frequency operation.
(f)	Output contacts:	Two output contacts per stage to be capable of repetitively making and breaking for 1000 operations.

CCA.4.1.2 The High Frequency Relays to be used shall be in accordance with the requirements of the relevant Agreement. They should have a setting range of 50 Hz to 52 Hz 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 High Frequency Relays for automatic installations is given as an

indication, without prejudice to the provisions that may be included in a relevant Agreement:

(a)	Frequency settings:	52-50Hz in steps of 0.01Hz
(b)	Measurement period selectable settings:	Within a minimum settings range of 4 to 6 cycles;
(c)	Operating time:	Between 100 and 150ms dependent on measurement period setting.
(d)	Voltage lock-out (under voltage blocking)	Selectable within a range of 50% to 90% of nominal voltage.
(e)	Facility stages:	Minimum of two stages of Frequency operation.
(f)	Output contacts:	Two output contacts per stage to be capable of repetitively making and breaking for 1000 operations.

CCA.4.2 Under-Frequency Load Shedding Relay Voltage Profiles

CCA.4.2.1 It is essential that the voltage supply to the under-frequency Load Shedding Relays shall be derived from the primary System at the supply point concerned so that the Frequency of the under-frequency Load Shedding Relays input voltage is the same as that of the primary System which require the use of a secure supply obtained from voltage transformers directly associated with the grid transformer(s) concerned, the supply being obtained where necessary via a suitable automatic voltage selection scheme.

CCA.4.3 Scheme Requirements

CCA.4.3.1 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 would 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 will not be reduced by more than 4% due to relay failure.

(b) Outages - Low Frequency Demand shedding schemes will be engineered such that the amount of Demand under control is as specified by the GSO and is not reduced unacceptably during equipment outage or maintenance conditions.

<Connection Code - End of Appendix 4>

<End of the Connection Code>

Operating Code (OC)

OC.1 Preamble

OC.1.1 The Grid Code is a a code developed and issued by the Commission. The Grid Code is composed by a Main Code, containing the main provisions structuring the purpose, the scope, the governance and some general requirements, and by additional codes, containing the specific technical rules for different subjects related to the operation of the Grid system.

OC.1.2 According to section 50A of the Electricity Supply 1990 [*Act 447*], the Commission may develop and issue such additional codes as it deems fit and expedient or the Minister may direct from time to time, as the case may be.

OC.2 Amendment

OC.2.1 The Commission may at any time amend, modify, vary or revoke such additional codes or any part thereof.

Operating Code No.1 (OC1): Demand Forecast

OC1.1 Introduction, Objectives and Scope

OC1.1.1 The provisions of sections MOC1.1, MOC1.2 and MOC1.3 of the Main Code shall apply to this Operating Code No.1: Demand Forecast.

OC1.2 Data Required by the Single Buyer in Operational Planning Phase and Programming Phase

OC1.2.1 General

OC1.2.1.1 Users shall provide the necessary information required in DRC8.5 and DRC8.6 to the Single Buyer at the time and in the manner agreed between the relevant parties to enable the Single Buyer to carry out the necessary Demand forecast for the Operational Planning Phase and Programming Phase. Users shall notify the Single Buyer immediately of any significant changes to the data submitted in accordance with DRC8.5 and DRC8.6.

OC1.2.1.2 In preparing the Demand forecast, the Single Buyer shall take into account the information provided by DRC8.5 and DRC8.6, the factors detailed in OC1.4 and also any relevant forecast or actual Demand growth data provided under the Planning Code for new or modification to existing connections.

OC1.2.2 Externally Interconnected Parties

OC1.2.2.1 It is the responsibility of the Single Buyer to request in the manner and format that have been specified in the relevant Agreement with each Interconnected Party of the hourly Active Power Demand to be imported from or exported to the Interconnected Party over the total time period agreed in the relevant Agreement.

The GSO will be responsible for the calculation of the Net Transfer Capacity of the interconnector, which is based on a methodology defined in the relevant Agreement.

OC1.3 Data Required by the GSO and Single Buyer in the Post Operational Control Phase

OC1.3.1 The GSO and Single Buyer may also require information in the Post Operational Control Phase for future forecasting purposes. Such information shall be provided at the time and in the manner agreed by the relevant parties.

OC1.3.2 The net station output in Active Power and Reactive Power of each Generating Module, Energy Storage Unit and Aggregator with a capacity of 30 MW and above will be monitored in real time at the GSO control centre. The output of Active Power and Reactive Power of Generating Modules, Energy Storage Units and Aggregators with a capacity of below 30MW may be monitored by the GSO at its control centre if the GSO, acting reasonably, decides to do so.

OC1.3.3 The GSO may request the Generators to provide half-hourly Active Power and Total Daily Energy data in respect of each Generating Module that does not have direct monitoring facilities for use by the GSO. Such information shall be provided to the GSO in the manner and format approved by the GSO, by 0300 hours on the following day.

OC1.4 Factors to be considered for Demand Forecast

OC1.4.1 General

OC1.4.1.1 The GSO and Single Buyer will take into account the factors described in OC1.4.2 to OC1.4.6 when conducting Demand forecasting, as well as any other information that may be material or supplied by Users as described in DRC8.5, DRC8.6 and OC1.2.2.

OC1.4.2 Historical Demand Data

OC1.4.2.1 When implementing the demand forecast the GSO and Single Buyer shall take historical demand data into account.

OC1.4.2.2 Historical Grid System Demand profiles are compiled by the GSO and Single Buyer through SCADA, metered data, Energy sales data from the Distributors and information obtained pursuant to the Post Operational Control Phase in OC1.3.

OC1.4.3 Weather information

OC1.4.3.1 When implementing the demand forecast for operation the GSO and Single Buyer shall consider the effect of weather and its correlation with demand. Weather parameters obtainable on regional basis and in major cities that must be considered by the GSO and Single Buyer include; temperature, rain and its duration, cloud cover, seasonal effects, e.g., Northeast Monsoon and hot spells in between monsoon seasons.

OC1.4.4 Incidents of Major Events or Activities Known in Advance

OC1.4.4.1 The GSO and Single Buyer in implementing the demand forecast for operation shall take into account the incidence of major events known to the GSO and Single Buyer in advance which may affect the Demand on the Grid System, for example, extended public holidays.

OC1.4.5 Committed Flows from External Parties

OC1.4.5.1 The GSO and Single Buyer in implementing the demand forecast for operation shall take into account import or export commitments with Interconnected Parties including impact of TPA.

OC1.4.6 Generation Forecasts from Embedded Generation

OC1.4.6.1 The GSO and Single Buyer in implementing the demand forecast for operation shall take into account the Generation forecasts provided by the Users and related to the non-dispatchable Embedded Generation.

<End of the Operating Code No.1: Demand Forecast>

Operating Code No.2 (OC2): Outage and Other Related Planning

OC2.1 Introduction, Objectives and Scope

OC2.1.1 The provisions of sections MOC2.1, MOC2.2 and MOC2.3 of the Main Code shall apply to this Operating Code No.2: Outage and Other Related Planning.

OC2.2 OC2.2 Submission of Planned Outage Schedules by Users

OC2.2.1 General

OC2.2.1.1 The Users shall provide GSO with the data described under DRC8.2 for Provisional Outages Schedules and DRC8.3 for Indicative Outage Schedules.

OC2.2.2 Interconnected Parties

OC2.2.2.1 Because Interconnected Parties have knowledge of both generation and transmission outages on the Power Systems they are involved with, it is the responsibility of the Single Buyer and the GSO to ensure that agreements are put in place and reviewed regularly with each Interconnected Party for exchange of information on operation in the Interconnected Party's System that may affect the Grid System.

OC2.3 OC2.3 Planning of Generation Outages

OC2.3.1 Preparation of Generation Outage Plan from 5 Years Ahead to 1 Year Ahead

OC2.3.1.1 The GSO is responsible for the coordination of Generation outages and the preparation of the Generation Outage Plan from Year 1 to Year 5 whereby Year 1 will be the provisional outage plan while Year 2 to Year 5 will be an indicative outage plan. For PPM & Energy Storage Unit, GSO will be responsible to prepare a provisional outage plan for Year 1 only.

OC2.3.1.2 During the preparation of the Generation Outage Plan, the GSO will endeavour to accommodate all outage requirements from Generators. However, there may be occasions when an outage cannot be met, and this will require additional consultation between the GSO and Users to formulate a best fit Generation Outage Plan

OC2.3.1.3 The GSO will issue to Users the First Draft Generation Outage Plan by the end of August of Year 0. Users have, until 15th October of Year 0, to notify the GSO of any objections to this first draft of the Generation Outage Plan. The GSO will then consult Users to resolve any differences over the first draft Generation Outage Plan and produce a final Generation Outage Plan by the end of November of Year 0.

OC2.3.1.4 In not less than 14 days prior to the outage start date, the Generator shall re-confirm their outage date by submitting the outage confirmation form on the planned outage to the GSO for approval.

For any rescheduling of planned outages, the Generator shall provide the GSO with at least 72 hours prior written notice where the notice shall include the anticipated start date, time and duration to obtain the approval of the GSO.

For the planned outage that is expected to complete earlier than the date, time and duration approved above, the Generator shall at its best endeavor provide a 24-hour notice in advance to the GSO.

OC2.3.1.5 Once the Generation Outage Plan is issued by the GSO, it can only be changed—

(a) by order of the GSO for reasons of security of the Grid System provided that safety of any equipment is not compromised and that the order is not in violation of any statutory requirements;

(b) by approval of the GSO prior to the commencement of the outage, for reasons related to security of supply, security of the Grid System, safety of User’s staff, safety of User’s equipment or safety of members of the public; or

(c) by agreement between the GSO and a Generator where only that Generator is affected by the proposed changes.

OC2.3.1.6 When a User cannot reach agreement with the GSO concerning the Generation Outage Plan, the dispute will be settled in accordance with the Grid Code Dispute Resolution Procedure, contained in the General Conditions (GC).

OC2.3.1.7 The GSO shall share at all times with the Single Buyer all relevant information related to the preparation of the Generation Outage Plan. The GSO shall also take into consideration any information provided by the Single Buyer for the preparation of the Generation Outage Plan.

OC2.3.2 Unplanned and Forced Outages

OC2.3.2.1 In this context Unplanned Outage refers to Generation outage not included in the Final Generation Outage Plan established by the GSO by the end of November of Year 0.

OC2.3.2.2 Where due to unavoidable circumstances a Generator needs to arrange an Unplanned Outage then the User must give at least 72 hours notification prior to the Unplanned Outage and submit it to the GSO for approval. This will normally be provided in writing but where this is not possible, it may be provided by telephone or other electronic means provided that it is acknowledged by the GSO and a written record of the request is kept by the GSO and the User. Notification must be provided according to DRC8.4.

OC2.3.2.3 The GSO may request the User to make changes related to an Unplanned Outage programme when in the opinion of the GSO the Unplanned Outage would adversely affect the security of the Grid System. For any outage rescheduling in 72 hours GSO may reschedule outages less than 72 hours to coincide with the low demand period (weekend and public holidays). User will send written confirmation of their agreement or disagreement with the new Unplanned Outage date and time to the GSO.

OC2.3.2.4 Forced outages are Unplanned Outages requested by Generators less than seventy-two (72) hours before the effective outage start date, which are not possible to postpone because it could affect the safety of people and equipment or the security of the Grid System. For a Forced Outage, the GSO shall take all reasonable measures to maintain the integrity and security of the Grid System.

OC2.4 Planning of Transmission Outages

OC2.4.1 Preparation of Transmission Outage Plan from 3 Years Ahead to 1 Year Ahead

OC2.4.1.1 The GSO shall plan any transmission outages required as a result of construction or refurbishment or maintenance in Years 3 to 1 inclusive.

OC2.4.1.2 Users should bear in mind that the GSO will be preparing the Transmission Outage Plan on the basis of the previous year's Outage Plan, and, if a User's outages differ or conflict with the Approved User Outage Plan, the GSO need not alter its Transmission Outage Plan.

OC2.4.1.3 By the end of August of Year 0 the GSO will draw up a draft Transmission Outage Plan covering the period Years 1 to 3 ahead and the GSO will notify each relevant Users in writing of the aspects of the plan which may operationally affect such User including in particular proposed start and end dates of relevant Grid System outages.

OC2.4.1.4 The GSO will also indicate where a need may exist to use Operational Intertripping, emergency switching, Demand Control or other measures including restrictions (and reasons for such restrictions) on the dispatch of the Units to allow the security of the Grid System to be maintained within the Licence Standards.

OC2.4.1.5 The GSO shall have the right to request the Grid Owner to schedule outages to coordinate with other User or Power Station outages for the optimisation of the Grid System operation. The Grid Owner shall not unreasonably refuse such requests.

OC2.4.1.6 Users have, until 15 October of Year 0, to notify the GSO of any objections to this first draft of the Transmission Outage Plan. By the end of November of Year 0, the GSO will produce the Approved User Provisional Outage Plan.

OC2.4.1.7 By the end of November of Year 0, the GSO will produce the Final Transmission Outage Plan covering Years 1 to 3 (provisional for Year 1 and indicative for Year 2 to 3).

OC2.4.1.8 The GSO will notify each User in writing of the aspects of the plan which may operationally affect such User including in particular proposed start and end dates of relevant Grid System outages.

OC2.4.1.9 In addition, in relation to the final Transmission Outage Plan for Year 1, the GSO shall provide to each Generator only the details which may materially affect the Power Station of that Generator for that year. It should be noted that the final Transmission Outage Plan for Year 1 and the updates will not give a complete understanding of how the Grid System will operate in real time, as the Grid System operation may be affected by other factors unknown at the time of the plan and updates. Therefore, Users should place no reliance on the plan or the updates showing a set of conditions that will actually occur in real time.

OC2.4.1.10 The information contained in the final Generation and Transmission Outage plan (described in OC2.3.1 and OC2.4.1) such as generation availability and transmission network changes due to planned outages and project commissioning, besides other inputs such as Transmission Development Plan by the Grid Owner, would enable the GSO to conduct the Grid System security assessment study for Year 1 to Year 3 and to produce the relevant report by June of Year 1.

OC2.4.2 Unplanned, Emergency, Forced Outages and Planned Outages Changes

OC2.4.2.1 The Transmission Outage Plan for Year 1 issued under OC2.4.1 shall become the plan for Year 0 when by expiry of time, Year 1 becomes Year 0.

OC2.4.2.2 Any outage not included in the final Transmission Outage Plan established by the GSO shall be considered as either Unplanned, Emergency or Forced Outage.

OC2.4.2.3 Where due to unavoidable circumstances except for construction, refurbishment and maintenance works a User needs to arrange an Unplanned, Emergency or Forced Outage then the User must give notification as early as possible of the Outage request and submit it to the GSO for approval. This will normally be provided in writing but where this is not possible, it may be provided by telephone or other electronic means provided that it is acknowledged by both parties i.e. the GSO and the User. Notification must be provided according to DRC8.4. The GSO may agree to the unplanned outage request including outages for construction, refurbishment and maintenance works, subject to prevailing Grid System condition.

OC2.4.2.4 Unplanned Outages concern the 275 kV and 500 kV outages requested by Users at least one (1) month before the effective outage start date or the 132 kV outages requested by the Users at least one (1) week before the effective outage start date. For any outage request which are not compliant with the timeline above, the GSO may consider the request, subject to prevailing Grid System condition.

OC2.4.2.5 Emergency Outages are Unplanned Outages requested by the Users at least one (1) day before the effective outage start date.

OC2.4.2.6 Forced Outages are Unplanned Outages requested by the Users less than twenty-four (24) hours before the effective outage start date, which is not possible to postpone because it could affect the safety of people and equipment or the security of the Power System.

OC2.4.2.7 Each User may at any time during Year 0 request the GSO in writing for changes to the outages defined by them under OC2.2 in relation to that part of

Year 0. The GSO shall determine whether the changes are possible and shall notify the User within 30 days of the outage start date.

OC2.4.2.8 Where the GSO determines that any change so requested is possible and notifies the relevant User accordingly, the GSO will provide to each relevant User with a copy of the request to which it has agreed which relates to outages on the relevant User Systems. The information must only be used by the User in operating that User's System and must not be used for any other purpose or passed on to, or used by, any other business of that User or to, or by, any person within any other such business or elsewhere.

OC2.4.2.9 The GSO may request for the Grid Owner to make changes related to Planned, Unplanned or Emergency Outage programme when in the opinion of the GSO the Outage would adversely affect the security of the Grid System. The Grid Owner will send a written confirmation to the GSO agreement or disagreement of the new Outage date and time in writing but where this is not possible, it may be provided by telephone or other electronic means provided that a written record of the agreement or disagreement is kept by the GSO and the Grid Owner.

OC2.4.2.10 For a Forced Outage, the GSO shall take all reasonable measures to maintain the integrity and security of the Grid System.

OC2.4.2.11 The GSO may request the relevant User to provide information on load transfer capability between two or more Connection Points through the User's System.

OC2.4.2.12 When necessary during Year 0, the GSO will notify each User, in writing of those aspects of the Transmission Outage Plan in Year 0, which may, in the reasonable opinion of the GSO, operationally affect that User including in particular proposed start dates and end dates of relevant Grid System outages.

OC2.5 Programming Phase

OC2.5.1 Every month, by the end of the month, the GSO shall prepare a monthly Generation Outage Plan which covers the next three (3) months.

OC2.5.2 Every week, by Friday 1700 hours, the GSO shall prepare a weekly Generation Outage Plan which covers the next sixteen (16) days.

OC2.5.3 Every month, by the end of the month, the GSO shall prepare a monthly Transmission Outage Plan which covers the next two (2) months.

OC2.5.4 Every week, by Friday 1700 hours, the GSO shall prepare a weekly Transmission Outage Plan which covers the next nine (9) days.

OC2.5.5 Every working day, by 1700 hours, the GSO shall prepare a daily Transmission Outage Plan which covers the period until the next working day.

OC2.5.6 The GSO will notify each User, in writing of those aspects of the Outage Plan which may operationally affect that User including in particular proposed start dates and end dates of relevant outages and changes to information supplied by the GSO.

OC2.5.7 The GSO will also indicate where a need may exist to use Operational Intertripping, emergency switching, Demand Control or other measures including restrictions (and the reasons for such restrictions) on the Dispatch Units to allow the security of the Grid System to be maintained within the Licence Standards.

OC2.5.8 Users shall submit to the GSO, notification on confirmation of outages involving their Systems in not less than one (1) month for 275kV and 500kV and not less than one (1) week for 132kV, prior to the date of each outage.

OC2.6 Live Apparatus Working Requirements

OC2.6.1 General

OC2.6.1.1 The Grid Owner may undertake or the GSO may request the Grid Owner to undertake maintenance or refurbishment of energized transmission Plant or Apparatus which may lead to risk of trip. Within OC2.5 such maintenance or refurbishment work is referred to Live Apparatus Working.

OC2.6.1.2 Live Apparatus Working may take place as either a scheduled or unplanned activity or at the request of the GSO to secure the Grid System.

OC2.6.2 Scheduled Live Apparatus Working

OC2.6.2.1 Where the Grid Owner wishes to undertake Live Apparatus Working within its planned maintenance schedule it will inform the GSO of the requirement at least one (1) month prior to the intended start date. The GSO having due regard to the integrity and security the Grid System and safety will either agree or refuse the request. If the GSO refuses the request it will discuss the intended start and completion date of the proposed works with the view to agreeing revised intended start and completion dates with the Grid Owner.

OC2.6.3 Unplanned Live Apparatus Working

OC2.6.3.1 Where the Grid Owner in unavoidable circumstances finds it necessary to carry out Live Apparatus Working under circumstances other than as described in OC2.6.2 it will inform the GSO of its intention to carry out such Live Apparatus Working giving the intended start time and date and seeking acceptance from the GSO. The GSO having due regard to the integrity and security the Grid System and safety will either accept or refuse the request. Acceptance will not be unreasonably withheld.

OC2.6.3.2 In the event that safety of personnel or Plant or Apparatus or Equipment or the Power System is likely to be prejudiced by the proposed Live Apparatus Working it will not be undertaken.

OC2.6.4 Live Apparatus Working at the Request of the GSO

OC2.6.4.1 Where the GSO following examination of the Transmission Outage Plan determines that a scheduled outage might need to be refused because it might prejudice the security and integrity of the Grid System and following discussion with the Grid Owner alternative outage dates cannot be agreed, the GSO may request the Grid Owner to undertake Live Apparatus Working having due regard to the alternate security and integrity of the Grid System imposed by Live Apparatus Working in replacement of the outage.

OC2.6.4.2 The Grid Owner having due regards to all circumstances pertaining, as a result of the change from an outage to Live Apparatus Working, shall accept or reject such request. Acceptance will not be unreasonably withheld.

OC2.7 Data Exchange

OC2.7.1 All studies related to the preparation of the Outage Plan in operational timescale shall be carried out by the GSO. The GSO may at the request of a User carry out studies in relation to the preparation of the Outage Plan for that User. Both the GSO and the User shall make the necessary data to carry out the study available for the purposes of such study. Any information used in or arising from the studies must only be used by the User in operating that User’s System and must not be used for any other purpose or passed on to, or used by, any other business of that User or to, or by, any person within any other such business or elsewhere.

OC2.8 Notices for Inadequate Generation Capacity to Meet Demand

OC2.8.1 Identification of Risk of Inadequate Generation Capacity to meet Demand.

OC2.8.1.1 When preparing the Outage Plan at the different considered timeframes, the GSO identifies the periods during which a risk of inadequate generation capacity to meet demand exist.

OC2.8.1.2 In such cases, the GSO issues a notice in writing to:

(a) all Generators listing any period in which there is likely to be inadequate generation Capacity to meet Demand; and

(b) all Generators which may, in the reasonable opinion of the GSO be affected, listing any period in which there is likely to be an unsatisfactory localised inadequacy of generation Capacity, together with the identity of the relevant System Constraint Group.

The GSO and each Generator will take these into account in seeking to co-ordinate outages for that period.

OC2.8.2 Programming During Period of Inadequate Generation Capacity

OC2.8.2.1 By 1000 hours each Business Day each Generator shall provide the GSO and Single Buyer in writing with a best estimate of Dispatch Unit inflexibility, or CDGU unavailability due to a maintenance outage, on a daily basis for the period two (2) to fourteen (14) days ahead (inclusive).

OC2.8.2.2 By 1600 hours each Wednesday each Generator shall provide the GSO and Single Buyer in writing with a best estimate of Dispatch Unit inflexibility, or CDGU unavailability due to a maintenance outage, on a weekly basis for the period two (2) to seven (7) weeks ahead (inclusive).

OC2.8.2.3 Between 1600 hours each Wednesday and 1200 hours each Friday if the GSO, taking into account the estimates supplied by the Generators and Demand forecast for the period, foresees that —

(a) there is inadequate generation Capacity to meet Demand for any period within the period two (2) to seven (7) weeks ahead (inclusive), it will issue a notice in writing to all Users and the Commission listing any periods and levels of inadequacy within that period; and/or

(b) having also taken into account the appropriate limit on transfers to and from a System Constraint Group, the level of localised inadequacy of generation Capacity for any period within the period two (2) to seven (7) weeks ahead (inclusive) for a particular System Constraint Group, it will issue a notice in writing to all Users which may, in the reasonable opinion of the GSO be affected by that localised inadequacy of generation, listing

any periods and levels of localised inadequacy within that period. A separate notice will be given in respect of each affected System Constraint Group.

OC2.8.2.4 The GSO will then contact Generators in respect of their Power Station to discuss outages and whether any change is possible to the estimate of Dispatch Unit inflexibility or CDGU unavailability due to a maintenance outage. The GSO will also contact Users who have agreed to participate in Demand Response to discuss levels of firm Demand Response that can be activated.

OC2.8.2.5 If on the day prior to a Schedule Day, it is apparent from the Availability Declarations submitted by Generators under SDC1 that there will be inadequate generation Capacity to meet Demand and/or Localised inadequate generation Capacity to meet Demand (as the case may be), then in accordance with the procedures and requirements set out in SDC1, the GSO may contact Generators to discuss whether changes to inflexibility or Offered Availability are possible, and if they are, will reflect those in the Unit Schedule. The GSO will also invoke Energy Storage Operators, Aggregators and Demand Response to the extent that it is required to match generation and Demand.

OC2.9 Weekly Operational Plan

OC2.9.1 The Weekly Operational Plan provides the Generation outlook for the next week. Its aim is to optimize and strategize the weekly scheduling of Generators and fuel mix and also to highlight if there is shortage of generation to meet the demand for the following week.

OC2.9.2 The Weekly Operational Plan is prepared by the Single Buyer every Thursday and covers the period from 0000 hours on the Saturday following to immediately before 2400 hours on the second subsequent Monday. It is based on the weekly Generation Outage Plan prepared by the GSO.

OC2.9.3 The Weekly Operational Plan includes an indication of the level of Spinning Reserve to be utilised by the GSO in the Scheduling and Dispatch process.

<End of the Operating Code No.2: Outage and Other Related Planning>

Operating Code 2 Appendix 1 – Generation Parameters Required for Operational Purposes

OC2A1.1 Generation Planning Parameters

The following parameters are required in respect of each Dispatch Unit.

OC2A1.1.1 Regime Unavailability

Where applicable the following information must be recorded for each Dispatch Unit:

(a) Earliest synchronizing time—

(i) Monday

(ii) Tuesday to Friday

(iii) Saturday to Sunday

(b) Latest de-synchronizing time:

(i) Monday to Thursday

(ii) Friday

(iii) Saturday to Sunday

OC2A1.1.2 Synchronizing Intervals

(a) The Synchronizing interval between Dispatch Units in a Synchronizing Group assuming all Dispatch Units have been Shutdown for forty eight (48) hours;

(b) The Synchronizing Group within the Power Station to which each Dispatch Unit should be allocated.

OC2A1.1.3 De-Synchronizing Interval

A fixed value De-Synchronizing interval between Dispatch Units within a Synchronizing Group.

OC2A1.1.4 Synchronizing Generation

The amount of MW produced at the moment of Synchronizing assuming the Dispatch Unit has been Shutdown for forty eight (48) hours.

OC2A1.1.5 Minimum On-time

The minimum period on-load between Synchronizing and De-Synchronizing assuming the Dispatch Unit has been Shutdown for forty eight (48) hours.

OC2A1.1.6 Run-Up rates

A run-up characteristic consisting of up to three stages from Synchronizing Generation to Output Usable with up to two intervening break points assuming the Dispatch Unit has been Shutdown for forty eight (48) hours.

OC2A1.1.7 Run-down rates

A run down characteristic consisting of up to three stages from Output Usable to De-Synchronizing with breakpoints at up to two intermediate load levels.

OC2A1.1.8 Notice to Synchronize

The period of time normally required to Synchronize a Dispatch Unit following instruction from GSO assuming the Dispatch Unit has been Shutdown for forty eight (48) hours.

OC2A1.1.9 Minimum Shutdown time

The minimum interval between De-Synchronizing and Synchronizing a Dispatch Unit.

OC2A1.1.10 Two Shifting Limit

The maximum number of times that a Dispatch Unit may De-Synchronize per Schedule Day.

OC2A1.1.11 Regulation Parameters

(a) Spinning Reserve Level.

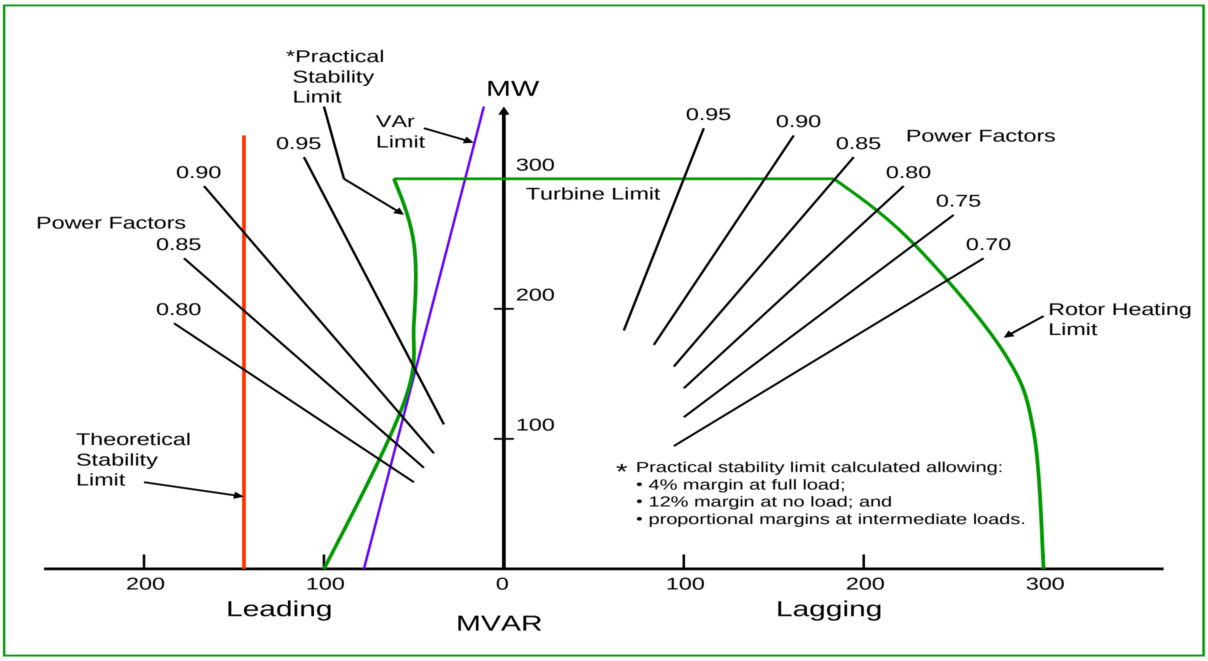
(b) Loading rate from Spinning Reserve Level to Output Usable.

(c) De-loading rate from Output Usable to the Spinning Reserve Level.

<End of the Operating Code No.2 – Appendix 1>

Operating Code 2 Appendix 2 – Generation Parameters –Generator Performance Chart

Example Generating Unit Capability Curve



<End of the Operating Code No. 2 – Appendix 2>

Operating Code 2 Appendix 3 – CCGT Module Matrix – Example Form

CCGT MODULE OUTPUT USABLE MW	**CCGT GENERATING UNITS** AVAILABLE								
	1st GT	2nd GT	3rd GT	4th GT	5th GT	6th GT	1st ST	2nd ST	3rd ST
	OUTPUT USABLE								
	150	150	150				100		
0MW to 150MW	Y								
151MW to 250MW	Y						Y		
251MW to 300MW	Y	Y							
301MW to 400MW	Y	Y					Y		
401MW to 450MW	Y	Y	Y						
451MW to 550MW	Y	Y	Y				Y		

<End of the Operating Code No.2 – Appendix 3>

Operating Code 2 Appendix 4 – Power Park Module Planning Matrix – Example Form

<table>
<tr><td colspan="4">Power Station [unique identifier]</td></tr>
<tr><td colspan="4">Power Park Module [unique identifier]</td></tr>
<tr><td rowspan="2">Power Park Unit Availability</td><td colspan="3">Power Park Units</td></tr>
<tr><td>Unit A</td><td>Unit B</td><td>Unit C</td></tr>
<tr><td>Description (make/model)</td><td></td><td></td><td></td></tr>
<tr><td>Output Usable (MW)</td><td></td><td></td><td></td></tr>
</table>

The Power Park Module Planning Matrix may have as many columns as are required to provide information on the different make and model for each type of Power Park Unit in a Power Park Module and as many rows as are required to provide information on the Power Park Modules within each Power Station. The description is required to assist identification of the Power Park Units within the Power Park Module and correlation with data provided under the Planning Code.

<End of the Operating Code No.2 – Appendix 4>

Operating Code No.3 (OC3): Operating Reserves and Response

OC3.1 Introduction, Objectives and Scope

OC3.1.1 The provisions of sections MOC3.1, MOC3.2 and MOC3.3 of the Main Code shall apply to this Operating Code No.3: Operating Reserves and Response.

OC3.2 Types of Operating Reserves

OC3.2.1 General

OC3.2.1.1 In preparing the Least Cost Unit Schedule, in accordance with SDC1, the Single Buyer will use the Demand forecasts, as detailed in OC1 and then match generation output to Demand plus Operating Reserve.

OC3.2.1.2 These reserves are essential for the stable operation of the Grid System and Generators and Energy Storage Operators will have their Generating Modules and Energy Storage Units tested from time to time in accordance with OC10 to ensure compliance with the relevant provisions of this Grid Code.

OC3.2.1.3 There are two types of Operating Reserve namely Spinning Reserve, and Non-Spinning Reserve. The types and requirements of responses provided by the Operating Reserve are described and specified in OC3.2.2 and OC3.2.3.

OC3.2.2 Spinning Reserve

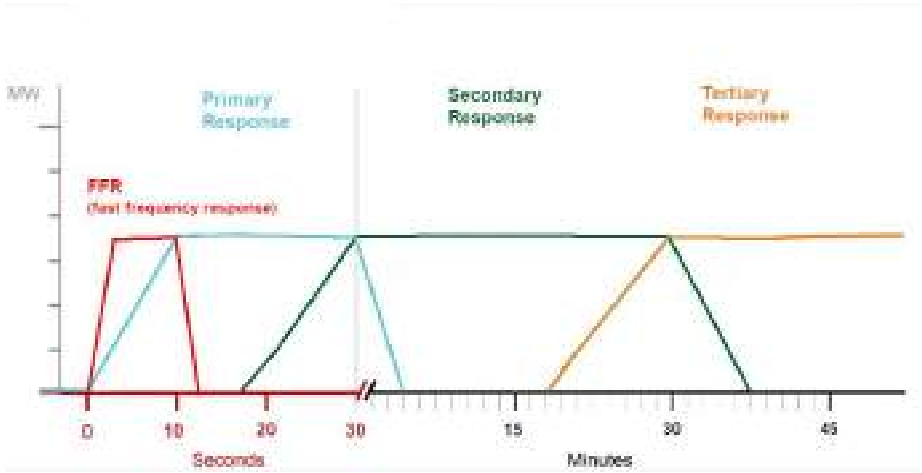
OC3.2.2.1 Spinning Reserve is the additional output from Generating Units or Energy Storage Units or by Interconnected Systems which are realisable in real time in order to arrest a deviation of system frequency due to a loss of generation or a sudden increase of demand or a loss of external Interconnection or mismatch between generation and demand. In accordance with the time in which the additional MW outputs in the form of Spinning Reserve can be delivered, the reserve response can be summarized as follows:

(a) Fast Frequency Response (FFR) is the response by Power Park Modules or Energy Storage Unit to a deviation of the Grid System Frequency which is required for arresting frequency rise/decline, in order to improve the frequency peak/nadir and ROCOF. It is expected to be fully realizable within two (2) seconds from the time of frequency changes and fully sustainable for at least ten (10) seconds.

(b) Primary Response is the automatic Active Power response from Unit to provide such a response, to a deviation of the Grid System frequency which requires changes in the generator unit output to arrest the fall or rise of frequency. The quantum of response shall be fully realisable within ten (10) seconds from the time of frequency change and fully sustainable for a at least a further twenty (20) seconds. Secondary Response is the automatic or manual Active Power response by a Unit, including hydro generators on synchronous condenser mode, to a deviation of the Grid System Frequency which is fully realisable within thirty (30) seconds from the time of frequency change and fully sustainable for at least thirty (30) minutes.

(c) Tertiary response is the automatic or manual response by a Unit in order to restore an adequate level of Primary and Secondary Reserve or to provide desired (in term of economic considerations) allocation of these reserves within the set of Units included in the Spinning Reserve or the Non-Spinning Reserve.

Illustration of the different Reserve Responses



OC3.2.2.2 The Primary Response corresponds to the control of the speed (or Active Power) of each Generating Unit by its individual governor (or equivalent device) which ensures that the driving torque (or Active Power) is a function of the system frequency.

OC3.2.2.3 Response through Interconnection Transfer is the automatic response available from the Interconnected Parties in response to changes in generation and demand balance in the Grid System. Response through Interconnection Transfer is part of the Primary Response.

OC3.2.2.4 The Secondary Response aims at restoring the frequency to its nominal value and restoring the power exchanges with the Interconnected Parties according to schedule.

OC3.2.2.5 Demand following by Automatic Generation Control (AGC) is the automatic response directed by the control mechanism at GSO Control Centre which reduces the error between generation and demand to a minimum by adjusting CDGU outputs. Demand following by AGC is part of the Secondary Response.

OC3.2.3 Non spinning Reserve

OC3.2.3.1 Non-spinning Reserve is the output available from standby Generating Units that can be synchronized and loaded up within one (1) hour when the Generating Unit is warm or hot and a longer timescale when the unit is cold to cater for abnormal Demand increase or further Generating Unit breakdowns.

OC3.2.3.2 The aim of the Non-spinning Reserve is also to restore the minimum required level of Primary and Secondary Reserves.

OC3.3 Provision of Operating Reserves

OC3.3.1 The amount of Operating Reserve required at any time will be determined by the GSO having regard to the Demand levels, Power Station availability shortfalls and the largest secured loss of generation or loss of import from or sudden export to interconnections.

OC3.3.2 When preparing the Unit Schedule, the Single Buyer shall allocate the Spinning Reserve to the various classes of Power Stations or Energy Storage Units so as to fulfil the required levels of response from the spinning reserve. The Single Buyer shall also make sure the required Spinning Reserve is spread among a sufficient number of Generators or Energy Storage Operators in a non-discriminatory way.

OC3.4 Data Requirements

OC3.4.1 The following data related to operating reserves are used by the GSO for operational purposes, but not limited to:

(a) Primary Response characteristics to frequency change data which describes the Energy Storage Unit or Generating Units' response at different levels of loading up to rated loading including governor droop and dead band characteristics of each Generating Unit or Energy Storage Unit;

(b) Secondary Response characteristics to frequency change data which describes the Energy Storage Unit or Generating Units' response at different levels of loading up to rated loading.

OC3.4.2 Generators or Energy Storage Operators shall register this data, in the format agreed with the Grid Owner and GSO under the Planning Code (PC) which is termed as the Registered Data and verified under OC10. Any revisions shall also be notified under PC and SDC1.

OC3.5 Operating Reserves from Interconnected Systems

OC3.5.1 Provision and receipt of Operating Reserve across an Interconnection are managed by the Single Buyer in consultation with the GSO. Where the use of an Interconnection is considered to be necessary to restore Operating Reserve on the Grid System then this will be determined by the GSO in accordance with the

Interconnection Agreement, and communicated to the Single Buyer. Where an Interconnected Party requires the use of the Operating Reserve of the Grid System to meet a sudden failure or shortage on its system then the GSO will take the necessary action to assist and restore the necessary Operating Reserve within the Grid System in accordance with this OC3, as if the loss of reserve had been due to problems within the Grid System.

OC3.5.2 The Energy delivered or received on the basis of the use of the Operating Reserve with an Interconnected Party shall be recorded by the GSO.

<End of the Operating Code No.3: Operating Reserves and Response>

Operating Code No.4 (OC4): Demand Control

OC4.1 Introduction, Objectives and Scope

OC4.1.1 The provisions of sections MOC4.1, MOC4.2 and MOC4.3 of the Main Code shall apply to this Operating Code No.4: Demand Control.

OC4.2 Procedure for Notification of Demand Control

OC4.2.1 The GSO will arrange to have available manual or automatic Load Shedding available and/or disconnection schemes to be employed throughout the Grid System. These schemes are intended for use when it is possible to carry out such Load Shedding or disconnection in the required timeframe by this means. These schemes could also involve voltage reductions and/or manual or automatic operation of the SCADA switching facilities and/or instructions to Users to disconnect Demand and/or Defence Plan and/or Special Protection Schemes.

OC4.2.2 Appropriate warnings shall be issued by the GSO when there is likely to be a requirement to shed Load in accordance with OC4.2.3 to OC4.2.6. These warnings will be categorized in accordance with the perceived levels of risk.

OC4.2.3 An Orange Warning - high risk of Demand Control - will, where possible, be issued by the GSO, twenty-four (24) hours before the event, by electronic means, when the GSO anticipates that it will or may instruct Users to implement Demand Control.

If possible, the GSO will precise the estimated required amount of load to be shed.

OC4.2.4 A Red Warning - Demand Control imminent - will, where possible, be issued by the GSO, thirty (30) minutes before the event, by telephone instructions, when the GSO will instruct Users to implement Demand Control.

If possible, the GSO will specify the estimated required amount of load to be shed.

OC4.2.5 It may also be necessary for the GSO to issue a warning of possible Demand Control to cover a local situation where the risk of serious overloading or voltage collapse is foreseen on the Plant or Apparatus of Power Stations or Grid System in a particular section of the System. Such warnings will be issued as Orange or Red warnings but specific to the locality.

OC4.2.6 The purpose of warnings is to obtain the necessary Load relief required with the least possible inconvenience to Consumers and, to that end, to ensure that response to requests for disconnection is both prompt and effective. Demand Control will, however, be required without warning if unusual and unforeseeable circumstances create severe operational problems.

OC4.3 Procedure for Implementation of Demand Control

OC4.3.1 Demand Control will be achieved by telephone instructions in the case of instructed Demand Control, to each relevant User and by direct switching by the GSO in the case of manual Demand Control.

OC4.3.2 Whether an Orange or Red warning has been issued or not, each relevant User shall abide by the instructions of the GSO with regard to Demand Control without delay.

OC4.3.3 The Demand Control must be achieved within the System of each User as far as possible uniformly across all Grid Supply Points unless otherwise instructed by the GSO.

OC4.3.4 Each User shall abide by the instructions of the GSO with regard to the restoration of Demand under this OC4.3 without delay. The User shall not restore Demand until it has received such instruction. The restoration of Demand must be achieved as soon as possible and the process of restoration must begin within two (2) minutes of the instruction being given by the GSO.

OC4.3.5 In circumstances of protracted shortage of generation or where a statutory instruction has been given (e.g. a fuel security period) and when a reduction in Demand is envisaged by the GSO to be prolonged, the GSO will notify the relevant Users of the expected duration.

OC4.3.6 Each relevant User will notify the GSO that it has complied with instructions of the GSO under this OC4.3, within ten (10) minutes of doing so, together with an estimation of the Demand reduction or restoration achieved.

OC4.4 Under-Frequency Load Shedding

OC4.4.1 The GSO shall make all necessary studies, arrangement and coordination to ensure sufficient quantum of automatic under-frequency Load Shedding as determined by the GSO in accordance with the requirements of the Grid System. The purpose of this is to seek to limit the consequences of a major loss of generation or an event on the Power System which leaves part or all of the Power System with a generation deficit.

OC4.4.2 Each User shall upon the instruction of the GSO implement, test, and maintain automatic frequency Load Shedding to the quanta as specified by GSO and confirmed in writing. The Load Shedding disconnection points may relate to individual or specific groups of Grid Supply Points, as determined by the GSO. The general characteristics of the type of equipment by which these quanta of Load Shedding shall be achieved will be in accordance with Appendix 4 of the CC.

OC4.4.3 The GSO shall monitor the availability of the quanta of Load Shedding using data from system disturbances and review the overall quanta at least once every three (3) years. Users shall make available all the data by which the GSO can monitor the performance of their Load Shedding schemes.

OC4.4.4 The load or demand of each User (instructed by the GSO to implement under-frequency Load Shedding) which is subject to under-frequency Load Shedding will be split into discrete MW blocks. The number, location, size and the associated Low Frequency Relay settings (frequency, ROCOF and time settings) of these blocks, will be as specified by the GSO following discussion with the User and will be reviewed in accordance with OC4.4.3 by the GSO. The distribution of the blocks will be such as to give a reasonably uniform disconnection within the System of the User across all Grid Supply Points.

OC4.4.5 Once under-frequency Load Shedding has taken place, the User on whose System it has occurred, will not reconnect until the GSO instructs that User to do so. Once the Frequency has recovered, each User will abide by the instructions of the GSO with regard to reconnection without delay.

OC4.4.6 Reconnection must be achieved as soon as possible and the process of reconnection must begin within two (2) minutes of the instruction being given by the GSO. The User will notify the GSO with an estimation of the Demand Reduction which has occurred under automatic under-frequency Load Shedding and will similarly notify the GSO about the restoration in each case within five (5) minutes of the disconnection or restoration.

OC4.5 Under-Voltage Load Shedding

OC4.5.1 The GSO shall make all necessary studies, arrangement and coordination to ensure sufficient quanta of automatic under voltage Load Shedding as determined by the GSO in accordance with the requirements of the Grid System. The purpose of this is to seek to limit the consequences of potential voltage instability.

OC4.5.2 Each User shall upon the instruction of the GSO implement, test, and maintain automatic under voltage Load Shedding to the quanta as specified by GSO and confirmed in writing. The general characteristics of the type of equipment by which these quanta of Load Shedding shall be achieved will be in accordance requirements of the CC.

OC4.5.3 The GSO shall monitor the availability of the quanta of Load Shedding using data from system disturbances and review the overall quanta at least once every three (3) years. Users shall make available all the data by which the GSO can monitor the performance of their Load Shedding schemes.

OC4.5.4 The load or demand of each User (instructed by the GSO to implement UVLS) which is subject to Under Voltage Load Shedding will be split into discrete MW blocks. The number, location, size and the associated low Voltage relay settings (voltage and time settings) of these blocks, will be as specified by the GSO following discussion with the User and will be reviewed in accordance with OC4.5.3 by the GSO. The distribution of the blocks will be such as to give a reasonably uniform disconnection within each area of the System across all Grid Supply Points.

OC4.5.5 Once under voltage Load Shedding has taken place, the User on whose System it has occurred, will not reconnect until the GSO instructs that User to do so. Once the voltage has recovered, each User will abide by the instructions of the GSO with regard to reconnection without delay.

OC4.5.6 Reconnection must be achieved as soon as possible and the process of reconnection must begin within two (2) minutes of the instruction being given by the GSO. The User will notify the GSO with an estimation of the Demand Reduction which has occurred under automatic under voltage Load Shedding and similarly notify the restoration in each case within five (5) minutes of the disconnection or restoration.

OC4.6 Emergency Manual Load Shedding or Disconnection

OC4.6.1 Each User will make arrangements that will enable it, following an instruction from the GSO, to disconnect loads under emergency conditions irrespective of Frequency within thirty (30) minutes. It must be possible to apply the Demand disconnections to individual or specific groups of Grid Supply Points, as determined by the GSO.

OC4.6.2 Each User shall abide by the instructions of the GSO with regard to disconnection under this OC4.6 without delay, and the disconnection must be achieved as soon as possible after the instruction being given by the GSO, and in any case, within the timescale registered in this OC4.6. The instruction may relate to an individual Grid Supply Point and/or groups of Grid Supply Points.

OC4.6.3 The GSO will notify a User who has been instructed under this OC4.6, of what has happened on the Grid System to necessitate the instruction, in accordance with the provisions of OC5.

OC4.6.4 Once a disconnection has been applied by a User at the instruction of the GSO, that User shall not reconnect until the GSO instructs it to do so.

OC4.6.5 Each User shall abide by the instructions of the GSO with regard to reconnection under OC4.6 without delay and shall not reconnect until it has received such instruction and reconnection must be achieved as soon as possible and the process of reconnection must begin within two (2) minutes of the instruction being given by the GSO.

OC4.6.6 The GSO may itself disconnect manually and reconnect Grid Connected Customers as part of a Demand Control requirement under emergency conditions.

OC4.6.7 If the GSO determines that emergency manual disconnection referred to in this OC4.6 is inadequate, the GSO may disconnect Network Operators and/or Grid Connected Customers at Grid Supply Points, to preserve the security of the Grid System.

OC4.6.8 Each User will supply details of the amount of Demand Reduction or restoration actually achieved to the GSO.

OC4.7 Rota Demand Control for Managing Longer Term Emergencies

OC4.7.1 As well as reducing Demand, with the objective of preventing any overloading of Apparatus and/or when there is insufficient generation to meet forecast Demand, or in the event of fuel shortages and/or water shortages at hydro-CDGUs, the GSO may utilise this OC4.7 to initiate Demand disconnections.

OC4.7.2 The GSO in coordination with the Distributors will prepare rota disconnection plans for levels of Demand disconnection in accordance with the Distributors codes and practice. Assignment of rota disconnection plans is under purview of the Distributors. These rota disconnection plans will be reviewed at least once in three (3) years or as and when necessary.

OC4.7.3 Rota disconnection will be applied following and in accordance with the warning system specified in OC4.2.

OC4.8 Scheduling and Dispatch

OC4.7.4 During Demand control, Scheduling and Dispatch in accordance with normal operation may cease and will not be re-implemented until the GSO decides, in each case in accordance with the provisions of the SDCs. The GSO will inform Users of the schedule.

<End of the Operating Code No.4: Demand Control>

Operating Code No.5 (OC5): Operational Liaison

OC5.1 Introduction, Objectives and Scope

OC5.1.1 The provisions of sections MOC5.1, MOC5.2 and MOC5.3 of the Main Code shall apply to this Operating Code No.5: Operational Liaison.

OC5.2 Operational Liaison Terms

OC5.2.1 Within this OC5 the term “Operation” means a previously planned and instructed action relating to the operation of any Plant or Apparatus that forms a part of the Grid System.

OC5.3 Procedures for Operational Liaison

OC5.3.1 The GSO and Users shall nominate persons and contact locations and agree on the communication channels to be used in accordance with the Connection Code (CC) for the necessary exchange of information to make effective the exchange of information required by the provisions of this OC5. There may be a need to specify locations where personnel can operate, such as Power Stations, control centres etc., and manning levels to be required, for example, 24 hours, official holiday cover etc. These arrangements may have been agreed upon producing the Site Responsibility Schedule pursuant to the CC.

OC5.3.2 All Users shall liaise with the GSO to initiate and establish any required communication channel between them.

OC5.3.3 SCADA equipment, remote terminal units, phasor measurement units, or other means of communication specified in the CC may be required at the User's site for the transfer of information to and from the GSO. As the nature and configuration of communication equipment required to comply with will vary between each category of User connected to the Grid System, it will be necessary to clarify the requirements in the relevant Agreement. All equipment shall comply with international standards such as International Electrotechnical Communication (IEC) standards. Information between the GSO and the Users shall be exchanged on the reasonable request from either party.

OC5.4 Requirements to Notify

OC5.4.1 General Requirements

OC5.4.1.1 In the case of an Operation or Event on the User System which will have or may have an Operational Effect on the Grid System or other User Systems, the User shall notify the GSO in accordance with this OC5.4.

OC5.4.1.2 The GSO shall inform other Users who in its reasonable opinion may be affected by that Operational Effect.

OC5.4.2 Situations Requiring Notifications

OC5.4.2.1 While in no way limiting the situations and or conditions requiring notification, the GSO and Users shall agree to review from time to time the Operations and Events which are required to be notified.

OC5.4.2.2 Examples of Operations where notification by the GSO or Users may be required under OC5 are:

(a) the implementation of planned outage of Plant and/or Apparatus pursuant to OC2;

(b) issue of dispatch instruction;

(c) the operation of circuit breaker or isolator/disconnector;

(d) confirmation of planned outage.

OC5.4.2.3 Examples of Events where notification by the GSO or Users may be required under OC5 are:

(a) the operation of Plant and/or Apparatus in excess of its capability or may present a hazard to personnel;

(b) activation of alarm or indication of an abnormal operating condition;

(c) adverse weather condition;

(d) breakdown of, or faults on, or temporary changes in, the capability of Plant and/or Apparatus;

(e) increased risk of unplanned protection operation;

(f) abnormal operating parameters, such as a governor problem, fuel system trouble, or low/high temperatures;

(g) loss of communication – SCADA; and

(h) any other Event requested by the GSO.

OC5.4.3 Form of Notification

OC5.4.3.1 A notification under this OC5 shall be of sufficient detail to describe the Operation or Event that might lead or have led to an Operational Effect on the relevant Systems, although it does not need to state the cause. This is to enable the recipient of the notification to reasonably consider and assess the implications or risks arising from it. The recipient may seek to clarify the notification.

OC5.4.3.2 This notification may be in writing if the situation permits it, otherwise, the other agreed communication channels in OC5.3 shall be used.

OC5.4.4 Timing of Notification

OC5.4.4.1 A notification under OC5 for Operations which will have or may have an Operational Effect on the relevant Systems shall be provided in real time prior to the Operation and allow the recipient to consider the implications and risks which may or will arise from it before the start of the Operation.

OC5.4.4.2 A notification under this OC5 for Events which will have or may have or have had an Operational Effect on the relevant Systems shall be provided as soon as practically possible after the occurrence of the Event or after the Event is known or anticipated by the person issuing the notification.

OC5.4.5 Operational Communication

OC5.4.5.1 Operational communication between Users shall be made by ensuring the safety of people and equipment at all times.

OC5.4.5.2 During operational communication made by phone in real time between the GSO and a User, the issuer of the notification makes sure the recipient of the notification repeats the notification and that the understanding of the recipient is the same as the notification made by the issuer.

OC5.4.5.3 All real-time operational communications made by phone between the GSO and Users shall be recorded and stored for at least three (3) years.

OC5.5 Significant Incidents

OC5.5.1 Where an Event on the Grid System has had or may have had a significant effect on the User System or when an Event on the User System has had or may have had a significant effect on the Grid System or other User Systems, the Event shall be deemed a Significant Incident by GSO in consultation with the User.

OC5.5.2 Significant Incidents shall be reported in writing to the affected party in accordance with OC6.

OC5.5.3 Without limiting the general description set out in this OC5.5, a Significant Incident will include Events having an Operational Effect which can result in the following:

(a) voltage outside statutory limits;

(b) frequency outside statutory limits;

(c) system instability; or

(d) load disconnection greater than 50 MW.

OC5.5.4 Based on criteria defined by the Commission, some Significant Incidents shall be reported in writing to the Commission.

OC5.6 GSO System Warnings

OC5.6.1 Roles of GSO System Warnings

OC5.6.1.1 GSO System Warnings as described below provide information relating to System conditions or Events and are intended to —

(a) inform Users of the current state of the Grid System;

(b) alert Users to possible Grid System problems and/or Demand Control;

(c) indicate intended consequences for Users; and

(d) enable specified Users to be in a state of readiness to react properly to instructions received from GSO.

OC5.6.2 Recipients of GSO System Warnings

OC5.6.2.1 Where GSO System Warnings are applicable to System (except those relating to Red Warning - Demand Control imminent) conditions or Events which have widespread effect, GSO will notify relevant Users under this OC5.6.

OC5.6.2.2 Where in the considered opinion of the GSO, System conditions or Events may only have a limited effect, the GSO System Warning will only be issued to those Users who are or may in the judgement of the GSO be affected.

OC5.6.2.3 Where a Red Warning - Demand Control imminent is issued it will only be sent to those Users who are likely to receive Demand Control instructions from the GSO.

OC5.6.3 Preparatory Action

OC5.6.3.1 Where possible, and if required, recipients of the warnings should take such preparatory action as they deem necessary taking into account the information contained in the GSO System Warning. All warnings will be of a form determined by the GSO and will remain in force from the stated time of commencement until they are cancelled or superseded by the GSO.

OC5.6.3.2 Where a GSO System Warning has been issued to a Network Operator and is current, Demand Control should not (subject as provided below) be employed unless instructed by the GSO. If Demand Control is, however, necessary to preserve the integrity of the Network Operator's System, then the impact upon the integrity of the Power System should be considered by the Network Operator and where practicable discussed with the GSO prior to its implementation.

OC5.6.3.3 GSO System Warnings will be issued by telephone, by email, or by the electronic data transmission facilities agreed upon by the GSO and Users.

OC5.6.4 Types of GSO System Warnings

OC5.6.4.1 GSO System Warnings include warnings related to the conditions of the Grid Systems as well as the colour coded warnings associated with Demand Control as specified in OC4.2.

OC5.6.4.2 System Warnings related to the conditions of the System define the state of the Grid System at any time:

(a) Normal state: the System state in which the System is within operational security limits and will remain within operational security limits after the occurrence of any contingency, taking into account the effect of the available remedial actions;

(b) Alert state: the System state in which the System is within operational security limits, but a contingency has been detected and in case of its

occurrence the available remedial actions are not sufficient to keep the normal state;

(c) Emergency state: the System state in which one or more operational security limits are violated;

(d) Blackout state: the System state in which the operation of part or all of the Grid System is terminated;

(e) Restoration state: the System state in which the objective of all activities in the Grid System is to re-establish the System operation and maintain operational security after the blackout State or the emergency State.

OC5.6.4.3 The list of contingencies to be considered for the determination of the System state will be determined by the GSO.

OC5.6.4.4 System Warnings related to Demand Control are:

(a) Orange Warning - high risk of Demand Control; and

(b) Red Warning - Demand Control imminent

The above warnings are specified in OC4.2

OC5.6.5 Issuance of System Warnings

OC5.6.5.1 A System Warning related to the conditions of the System will be issued in such a way than, at any time, only one of the warnings will be active.

OC5.6.5.2 The System Warning to be considered by default is the normal state.

OC5.6.5.3 The actions to be implemented by the Users upon receipt of any System Warning related to the conditions of the System other than the normal state will be defined by the GSO.

OC5.6.5.4 Whenever a System Warning related to the conditions of the System is issued by the GSO, it will specify the actions to be implemented by the Users.

OC5.6.5.5 A System Warning related to Demand Control may be issued to Users in accordance with OC5.6.2 at times when there is inadequate System Margin, as determined and in the judgement of the GSO there is increased risk of Demand Control being implemented under OC4.3. It will contain the following information:

(a) the availability shortfall in MW;

(b) intended consequences for Users;

(c) if possible the percentage level or estimated volume of Demand Control required; and

(d) specify those Users who may subsequently receive instructions under OC4.3.

OC5.6.5.6 The issue of a GSO System Warning related to Demand Control is intended to enable recipients to plan ahead on the various aspects of Demand Control.

OC5.6.6 Cancellation of GSO System Warning

OC5.6.6.1 Any System Warning related to the conditions of the System issued by the GSO will supersede any warning sent previously. For the avoidance of doubt, the GSO will not give notification of a cancellation of a GSO System Warning related to the conditions of the System.

OC5.6.6.2 The GSO will give notification of a cancellation of GSO System Warning related to Demand Control to all Users issued when, in the judgement of the GSO, System conditions have returned to normal.

OC5.6.6.3 A cancellation of a GSO System Warning related to Demand Control will identify the type of GSO System Warning being cancelled.

OC5.6.7 General Management of GSO System Warnings

OC5.6.6.4 GSO System Warnings remain in force unless superseded or cancelled by the GSO.

OC5.7 Procedure for Information Flow During Commissioning and Compliance Tests

OC5.7.1 General

OC5.7.1.1 This section of the Grid Code deals with information flow during Commissioning Tests and Compliance Tests. It is designed to provide a framework for the exchange of relevant information and for discussion between the Single Buyer, Grid Owner and GSO and certain Users in relation to Commissioning Tests and Compliance Tests.

OC5.7.1.2 Commissioning Tests and Compliance Tests are carried out in accordance with the provisions of this OC5.7, at a User site or GSO Control Centre, and will normally be undertaken during commissioning or re-commissioning of Plant and/or Apparatus.

OC5.7.1.3 In the case of a Commissioning Tests, notification must be made where the test may, in the reasonable judgement of the person wishing to perform the test, cause, or have the potential to cause, an Operational Effect on a part or parts of the Power System but which with prior notice is unlikely to have a materially adverse effect on any part of the Power System, and may form part of an agreed programme of work.

OC5.7.1.4 In the case of a Compliance Tests, notification of the requirement will be made by the GSO to the User.

OC5.7.2 Notification

OC5.7.2.1 In order to undertake a Commissioning or Compliance Test, the User or the GSO or the Single Buyer, as the case may be, (the proposer) must notify the other (the recipient) of a proposed Commissioning or Compliance Test.

Reasonable advance notification must be given, taking into account the nature of the test and the circumstances which make the test necessary. This will allow recipients time to adequately assess the impact of the Commissioning or Compliance Test on their System.

OC5.7.2.2 The notification of the Commissioning Test, the test should be incorporated as part of any overall commissioning programme agreed between the GSO the Users, and must normally include the following information:

(a) the proposed date and time of the Commissioning Test;

(b) the name of the individual and the organization proposing the Commissioning Test;

(c) a proposed programme of testing; and

(d) such further detail as the proposer reasonably believes the recipient needs in order to assess the effect the Commissioning Test may have on relevant Plant and/or Apparatus.

OC5.7.2.3 The notification of the Compliance Test must normally include the following information:

(a) a proposed period in which the GSO or the Single Buyer proposes that a Compliance Test should take place;

(b) a proposed programme of testing.

The recipient of notification of a Compliance Test must respond within a reasonable timescale prior to the start time of the Compliance Test and will not unreasonably withhold or delay acceptance of the Compliance Test proposal.

OC5.7.2.4 Where the Single Buyer and GSO receives notification of a proposed Commissioning Test from a User, the GSO will consult those other Users whom it reasonably believes may be affected by the proposed Commissioning Test to seek their views. Information relating to the proposed Commissioning Test may be passed on by the GSO with the prior agreement of the Test Proposer. However, it is not necessary for the GSO to obtain the agreement of any such

User as Commissioning Tests should not involve the application of irregular, unusual or extreme conditions. The GSO may however consider any comments received when deciding whether or not to agree to a Commissioning Test.

OC5.7.2.5 The response from the recipient, following notification of a Commissioning Test must be one of the following:

(a) to accept the Commissioning Test proposal;

(b) to accept the Commissioning Test proposal conditionally subject to minor modifications such as date and time;

(c) not to agree to the Commissioning Test, but to suggest alterations to the detail and timing of the Commissioning Test that is necessary to make the Commissioning Test acceptable.

OC5.7.3 Final confirmation

OC5.7.3.1 The date and time of a Commissioning or Compliance Test will be confirmed between the GSO, the User, the Grid Owner and the Single Buyer together with any limitations and restrictions on operation of Plant and/or Apparatus.

OC5.7.3.2 The Commissioning or Compliance Test may subsequently be amended following discussion and agreement between the GSO, the User, the Grid Owner and the Single Buyer.

OC5.7.4 Execution

OC5.7.4.1 Commissioning or Compliance Tests may only take place when agreement has been reached and must be carried out in accordance with the agreed programme of testing and the provisions of the relevant Agreement.

OC5.7.4.2 The implementation of a Commissioning or Compliance Test will be notified in accordance with OC5.7.2.

OC5.7.4.3 Where elements of the programme of testing change during the Commissioning or Compliance Test, there must be discussion between the appropriate parties to identify whether the Commissioning or Compliance Test should continue.

<End of the Operating Code No.5: Operational Liaison>

Operating Code No.6 (OC6): Significant Incident Reporting

OC6.1 Introduction, Objectives and Scope

OC6.1.1 The provisions of sections MOC6.1, MOC6.2 and MOC6.3 of the Main Code shall apply to this Operating Code No.6.

OC6.2 Procedures

OC6.2.1 Procedures for Reporting Significant Incidents

OC6.2.1.1 While in no way limiting the general requirements to report Significant Incidents under OC6, a Significant Incident will include Events having an Operational Effect that will or may result in the following:

(a) operation of Plant and/or Apparatus outside their design limits;

(b) system voltage outside Normal Operating Condition limits;

(c) frequency outside Normal Operating Condition limits;

(d) system instability; and

(e) load disconnection greater than 50 MW.

OC6.2.1.2 The GSO and Users shall nominate persons and/or contact locations and communication channels to ensure the effectiveness of OC6, such persons or communication channels may be the same as those established in OC5. For any change in relation to the nominated persons, the contact locations and the communication channels, the GSO and Users shall promptly inform each other in writing.

OC6.2.1.3 In the case of an Event which has been reported to the GSO under OC5 by the User and subsequently determined to be a Significant Incident by the GSO and the Single Buyer, a written report shall be given to the GSO and Single Buyer by the User involved in accordance with OC6.2.2.

OC6.2.1.4 In the case of an Event which has been reported to the User under OC5 by the GSO and is subsequently determined to be a Significant Incident by the GSO, a written report shall be given to the User involved by the GSO in accordance with OC6.2.2.

OC6.2.1.5 In all cases, the GSO shall be responsible for the compilation of the final report before issuing to relevant parties, including the Commission.

OC6.2.2 Significant Incident Report

OC6.2.2.1 The report on the Significant Incident shall be in writing or any other means mutually agreed between the two parties and shall contain:

(a) confirmation of the notification given under OC5;

(b) a more detailed explanation or statement relating to the Significant Incident from that provided in the notification given under OC5; and

(c) any additional information which has become known with regards to the Significant Incident since the notification was issued.

OC6.2.2.2 The report shall as a minimum contain the following details:

(a) date, time and duration of the Significant Incident;

(b) location;

(c) Plant and/or Apparatus involved;

(d) description of the Significant Incident under investigation and its cause; and

(e) conclusions and recommendations of corrective and preventive actions, if applicable.

OC6.2.2.3 A written report shall be prepared as soon as reasonably practical after the initial notification under OC5.

OC6.2.2.4 In general, the GSO will request the relevant User for a preliminary written report under OC6 within four (4) hours of being aware of any such Significant Incidents. The User will then have to investigate the cause of the incident and to take any corrective measures necessary and submit the formal written report within three (3) Business Days. When a User requires more than three (3) Business Days to report an occurrence of a Significant Incident, the User may request additional time up to two (2) calendar months from the GSO to carry out the relevant investigations and submit the final report.

OC6.2.2.5 If the Significant Incident occurred on the Grid System, the GSO will submit a preliminary report to the Commission within three (3) Business Days of the Significant Incident and the final report will be produced within two (2) calendar months by the identified User(s).

<End of the Operating Code No 6: Significant Incident Reporting>

Operating Code No.7 (OC7): Emergency Operations

OC7.1 Introduction, Objectives and Scope

OC7.1.1 The provisions of sections MOC7.1, MOC7.2 and MOC7.3 of the Main Code shall apply to this Operating Code No.7: Emergency Operation.

OC7.2 Procedures

OC7.2.1 General

OC7.2.1.1 The GSO shall establish, maintain and regularly review a Grid System Defence Plan and Grid System Restoration Plan in conjunction with Users, which can be called into action immediately during Grid System Emergencies.

OC7.2.1.2 In relation to the requirement in OC7.2.1.1, all Users shall also establish, maintain and regularly review their respective Restoration Plans and in doing so must be aware of the of the Grid System requirements through consultation with the GSO.

OC7.2.1.3 It is important that all Users identified under MOC7.3 make themselves fully aware of contingency requirements, as failure to act in accordance with the instructions of the GSO will risk further disruptions to the Grid System and, potentially, supplies to all Consumers.

OC7.2.1.4 The purpose of the Grid System Defence Plan is to undertake measures in preventing Grid System Emergency conditions. It includes but is not limited to the under-frequency Load Shedding plan and to the use of Special Protection Schemes.

OC7.2.1.5 When the Grid System is under Emergency conditions, the GSO is able to decide to cease the normal Scheduling and Dispatch process including TPA and inform Users accordingly. The normal Scheduling and Dispatch process will only be re-implemented under instruction of the GSO.

OC7.2.2 Determination of Grid System Emergency Conditions

OC7.2.2.1 The GSO will activate the Grid System Restoration Plan when, any of the following has occurred:

(a) data arriving at the GSO Control Centre indicating a Grid System split or the existence of a risk to Plant or Apparatus which requires that Plant or Apparatus be off-loaded or shutdown, which itself constitutes a Critical Incident;

(b) reports or data from Power Stations that a Generating Module has tripped or needs to be offloaded which constitutes a Critical Incident;

(c) reports or data via the SCADA system that indicates a Partial Blackout or Total Blackout may be imminent or exists;

(d) loss of GSO Control Centre;

(e) fuel supply emergency;

(f) report from the field staff or Users or Public of imminent danger to Critical Installation of the Grid System;

(g) adverse weather conditions; or

(h) reports of fire affecting or may be affecting critical installations of the Grid System, imminent tower collapse, bomb threat etc.

OC7.2.3 Grid System Restoration Plan

OC7.2.3.1 The Grid System Restoration Plan will serve as a guide during System Emergencies and will outline the operational structure to facilitate a safe and prompt restoration process and avoidance of disruption of supplies.

OC7.2.3.2 The Grid System Restoration Plan will also address the restoration priorities of the different Consumer groups and also the ability of each CDGU to accept sudden loading increases due to the re-energising of Demand blocks.

OC7.2.3.3 Certain Power Stations will be registered as Black Start Power Stations having a capability for at least one of their CDGUs to Start-up from Shutdown and to energise a part of the Power System, or be Synchronized to the System, upon instruction from the GSO within the shortest reasonable time, without an external electrical power supply.

OC7.2.3.4 The generic tasks outlined in the Grid System Restoration Plan are:

(a) if communication is cut off, the re-establishment of full communications between parties;

(b) the determination of the status of the post Critical Incident system including the status and condition of HV Apparatus and Plant;

(c) actions and instructions to Users for restoration or recovery of Grid System from imminent disruption of supplies;

(d) actions and instructions to Users for restoration of Grid System from loss of supplies;

(e) instructions by the GSO to the relevant parties;

(f) coordination procedures between adjacent Users;

(g) mobilisation and assignment of priorities to personnel;

(h) preparation of Power Stations and the Grid System for systematic restoration;

(i) re-energization of Power Islands using Black Start Power Stations if necessary;

(j) re-synchronization of the various Power Islands to restore the interconnected Grid System;

(k) staffing levels requirements during emergency;

(l) priority of categories of loads to restored as determined by the GSO; and

(m) an audit of the Grid System after restoration to ensure that the overall Grid System is back to normal and all Demand is connected, and in line with the reporting requirements of OC6 all data has been collected for reporting purposes.

OC7.2.3.5 The Grid System Restoration Plan shall be developed and maintained by the GSO. The GSO will issue the Grid System Restoration Plan and subsequent revisions to appropriate Users and other relevant parties.

OC7.2.3.6 The implementation of the Grid System Restoration Plan may not be in the order as defined in the plan and this will be up to the discretion of the GSO.

OC7.2.4 Restoration procedures

OC7.2.4.1 The procedure for the Grid System Restoration Plan shall be that notified in writing by the GSO to the User for use at the time of System Emergencies.

OC7.2.4.2 Each User shall abide by the GSO‘s instructions during the restoration process, unless doing so would endanger life or would cause damage to Plant or Apparatus.

OC7.2.4.3 To expedite restoration in the event of an area shutdown of generating capability, each System should set up necessary operating instructions and procedures to cover emergency conditions, including loss of communications.

OC7.2.4.4 Due to the complexities and uncertainties of recovery from total or partial System collapse, the contingency plans must be in place to address the overall strategy of restoration and management of the process. These plans form the Grid System Restoration Plan.

OC7.2.4.5 During total or partial collapse and during subsequent recovery, the Grid System may be operated outside normal voltage and Frequency standards. In total or partial collapse and during the subsequent recovery, the normal Schedule and Dispatch process will cease and will only be re-implemented under instruction of the GSO.

OC7.2.4.6 Generators shall, in consultation with the GSO, set up their own contingency plans to cater for normalization of their own system after a total or partial collapse in their area. All contingency plans shall/may be reviewed and updated once in three (3) years or as when the GSO determines it necessary in order to reflect changes in the Grid System and other Systems and to address any deficiency found.

OC7.2.4.7 Where necessary, the GSO can vary these procedures in real-time where, under System Stress conditions, the GSO in its reasonable opinion considers that such a change is required. Users are required to comply with instructions of the GSO, unless to do so would endanger life or would cause damage to Plant or Apparatus.

OC7.2.4.8 The GSO shall ensure that a systematic restoration process is conducted by energising each part of Power Island in such a way as to avoid load rejection by the CDGUs concerned. When energising a substation that has become de-energised, Isolation of certain outgoing feeders at that substation may be necessary to prevent excessive load pick-up on CDGUs connected to that Power Island or the Grid System as the case may be, upon re-energisation. Where a Power Island has become de-energised, meaning that no CDGUs are operating to supply Consumer Demand, then the GSO will need to call on the service of Black Start Power Stations to re-establish voltage and frequency in that Power Island.

OC7.2.4.9 The following switching guidelines shall be used in preparation for restoration:

(a) the GSO Control Centre establishes its communication channels for the Power Island concerned;

(b) the GSO Control Centre sectionalises the Grid System into pre-determined Power Islands;

(c) if possible, power should be made available at the auxiliary boards of the Power Stations within four (4) hours of the system collapse to start CDGUs;

(d) during the restoration, steel mills have to be instructed not to operate their arc furnaces;

(e) a selective open strategy is adopted for 275 kV or 132 kV Active Circuits at transmission substations;

(f) a feeding strategy is adopted for the Black Start Power Stations; and

(g) a cross feeding strategy is adopted for utilising Black Start Power Stations to support the start-up of other Power Stations in the same Power Island.

OC7.2.5 Demand Restoration

OC7.2.5.1 The re-energisation of transmission substations and Power Islands will involve the balancing of available generation Capacity to Grid System Demand. It is the responsibility of the GSO Control Centre to have details of each transmission substation Demand by transmission circuit, in order that the CDGU's concerned shall not be presented with load pickup in excess of the weakest CDGU's loading acceptance limit. If this is not followed, this can result in load-rejection by a CDGU.

OC7.2.5.2 Re-energisation procedures should address the following issues:

(a) CDGU maximum load pickup shall not be exceeded;

(b) long transmission lines should be energised with shunt reactors in circuit;

(c) Demand shall be predicted and also monitored in real time to determine when additional transmission circuits can be re-energised; and

(d) At least one Generating Unit in each Power Island to be operating in frequency sensitive mode.

OC7.2.5.3 Wherever practicable, high priority Consumers such as Federal Government Administrative Centre shall have their Demand restored first.

OC7.2.5.4 Such a priority list, as contained in the Grid System Restoration Plan shall be prepared on the basis of Consumer categories and the Power Islands by the GSO for the approval of the Commission.

OC7.2.5.5 During restoration of Demand, the Grid System Frequency shall be monitored to maintain it above 49.5Hz as far as is possible.

OC7.2.6 Dealing with System Splits

OC7.2.6.1 Where the Grid System splits, it is important that any Power Islands that exist are re-synchronized as soon as practicable to the main Grid System, but where this is not possible, Consumers should be kept on-supply from the Power Islands to which they are connected.

OC7.2.6.2 When CDGUs have shut down and sections of the network are experiencing blackout conditions then the GSO will have to consider the available generating Capacity including any Operating Reserve and the prospective Demand that will be restored to ensure each Power Island operates within the Frequency limits given in the Licence Standard.

OC7.2.6.3 In the event of an extended duration system split the GSO shall apply a contingency plan which may include issuing of warnings, load disconnection and any other measures deemed necessary.

OC7.2.6.4 Where Power Islanding occurs under System Stress, then the GSO Control Centre should also have available rota Load Shedding programmes to avoid Customers being disconnected indiscriminately and being left without supplies for extended periods

OC7.2.6.5 The GSO and Users shall agree on the communication channels to be used for the purpose of implementation of this OC7. These may be similar to the agreed channels identified pursuant to Operational Liaison OC5.

OC7.2.7 Grid System Restoration Plan Familiarisation Plan and Test

OC7.2.7.1 It shall be the responsibility of the User to ensure that any of its personnel who may reasonably be expected to be involved in Grid System restoration 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 and comply with any procedures notified by the GSO.

OC7.2.7.2 The GSO shall be responsible for arranging training and exercises of relevant parties and with Interconnected Parties, to ensure that all parties are aware of their roles in this OC7. Once these parties are familiar with the role assigned by the GSO then exercises can be conducted, using simulators or other training methods as appropriate with the relevant parties covered by this OC7.

OC7.2.7.3 Users shall have the responsibility to ensure that their own staffs are familiar with their restoration procedures and coordination with the GSO and may seek the cooperation of the GSO in order to facilitate this requirement.

OC7.2.7.4 The GSO shall in consultation with each User on at least one occasion in three (3) years, carry out a Grid System Restoration drill. The content of the drill shall be notified in advance to the relevant parties, and a date and time for execution of the drill shall be agreed. Users must cooperate with any such drill.

OC7.2.8 Recovery Procedures from Abnormal Operating Conditions

OC7.2.8.1 The GSO shall establish its Grid System Restoration Plan with due regard to the requirements associated with abnormal operating conditions which may lead to issue of warnings related to imminent disruption of supply.

OC7.2.8.2 Following successful removal of such conditions through the implementation of the relevant parts of the Grid System Restoration Plan, the GSO shall withdraw the warning issued.

OC7.2.9 Loss of GSO Control Centre

OC7.2.9.1 In the rare event of the primary control centre of GSO Control Centre being evacuated or subject to major disruption of its function, for whatever reasons, the GSO shall resume control of the Grid System from an alternative control facility which will enable the GSO to ensure continuity of control functions until the primary control centre of GSO Control Centre can be restored.

OC7.2.9.2 While the alternative control facility is being established, the GSO shall handover the control of the Grid System to an interim control centre which is sufficiently equipped to control the Grid System until the alternative control facility is fully established.

OC7.2.9.3 The GSO shall also prepare all the necessary plans and procedures and from time to time conduct the necessary exercises to ensure that a satisfactory change-over can be achieved without prejudicing the integrity of the Grid System.

OC7.2.10 Fuel Supply Emergency

OC7.2.10.1 The Single Buyer and GSO shall prepare fuel supply inventory advice for primary, alternative and standby fuels as applicable in accordance with obligations placed by the Government of Malaysia on the electricity industry at the time of the connection application in accordance with CC6.4.13. The Generators shall report the compliance of their fuel stock with the obligations in the relevant Agreements to the Single Buyer and GSO in accordance with the reporting requirements in the relevant Agreements.

OC7.2.10.2 The Single Buyer and GSO shall report the adequacy of the fuel supply inventory to the Commission on an exception basis. In the event of any fuel supply shortages this reporting will be on a daily basis. Under these conditions the Single Buyer and the GSO shall abandon the Least Cost Unit Scheduling and revert to a Fuel Availability Based Scheduling conserving fuel supplies and taking all necessary measures to extend the endurance of the fuel supplies.

OC7.2.10.3 In the event that the Single Buyer or GSO foresees an imminent or possible fuel shortage or curtailment of supplies the Single Buyer or GSO shall also instruct Generators to increase their fuel stock to the full extent of their capacity available at the Power Station to ensure continued endurance.

<End of the Operating Code No.7: Emergency Operation>

Operating Code No.8 (OC8): Safety Coordination

OC8.1 Introduction, Objectives and Scope

OC8.1.1 The provisions of sections MOC8.1, MOC8.2 and MOC8.3 of the Main Code shall apply to this Operating Code No.8: Safety Coordination.

OC8.2 Procedures for Local Safety Instructions, Coordinators and Records of Safety Precautions

OC8.2.1 General

OC8.2.1.1 OC8 does not seek to impose a particular set of Safety Rules on the Grid Owner and other Users. The Safety Rules to be adopted and used by the Grid Owner and each User shall be those chosen by each party's management.

OC8.2.1.2 At all Grid Supply Points, the Safety Rules to be used by both the Grid Owner and the Associated Users shall be as determined by the Grid Owner after consultation with the GSO. Competencies of the Grid Owner personnel and User's staff may be certified by the Grid Owner as allowed by the Commission.

OC8.2.2 Defined Terms

OC8.2.2.1 Users should bear in mind that in OC8 only, in order that OC8 reads more easily with the terminology used in certain User's Safety Rules, the term "HV Apparatus" is defined more restrictively and is used accordingly in OC8. Users should, therefore, exercise caution in relation to this term when reading and using OC8.

OC8.2.2.2 In OC8 only the following terms shall have the following meanings:

(a) "HV Apparatus" means High Voltage electrical Apparatus forming part of a Network to which "Safety Precautions" must be applied to allow work to be carried out on that Network or a neighbouring Network.

(b) "Isolation" means the disconnection or separation of HV Apparatus from the remainder of the Network in accordance with the following:

(i) an Isolating device maintained in an isolating position. The isolating position must be either:

A. maintained by immobilising and/or locking of the isolating device in the isolating position and affixing an "Isolation Notice" to it. Where the isolating device is locked with a "Safety Key", the Safety Key must be retained in safe custody;

B. maintained and/or secured by electronic means provided that the entry of at least two (2) passwords are required before an action can be implemented; or

C. maintained and/or secured by such other method which must be in accordance with the "Local Safety Instructions" of the Network Controller or that User, as the case may be;

or:

(ii) an adequate physical separation which must be in accordance with, and maintained by, the method set out in the Local Safety Instructions of the Network Controller or that User, as the case may be, and, if it is a part of that method, an Isolation Notice must be placed at the point of separation.

(c) "Earthing" means a way of providing a connection between HV conductors and earth by an Earthing device which is either:

(i) immobilised and locked in the Earthing positions. Where the Earthing device is locked with a Safety Key, the Safety Key must be secured and kept in safe custody; or

(ii) maintained and/or secured in position by such other method which must be in accordance with the Local Safety Instructions of the Network Controller or that **User** as the case may be; or

(iii) temporary Earthing immediately adjacent to the area or work.

(d) For the purpose of the coordination of safety under this OC8 relating to HV Apparatus, the term "Safety Precautions" means Isolation and/or Earthing.

(e) "Network Controller" means the network control centre that is responsible for that part of the Grid System or Distribution Network that the User has its Grid Supply Point on.

OC8.2.2.3 In OC8, references to any relevant Agreement shall be deemed to include references to the application or offer thereof.

OC8.2.3 Local Safety Instructions

OC8.2.3.1 Either party may require that the Isolation and/or Earthing provisions in the other party's Safety Rules to be made more stringent by the issue by that party of a Local Safety Instructions affecting the Grid Supply Point concerned. Provided that these requirements are not unreasonable in the view of the other party, then that other party will make such changes as soon as reasonably practicable. These changes may need to cover the application of Isolation and/or Earthing at a place remote from the Grid Supply Point, depending upon the Network layout. Approval may not be withheld because the party required to approve reasonably believes the provisions relating to Isolation and/or Earthing are too stringent.

OC8.2.3.2 If following approval, a party wishes to change the provisions in its Local Safety Instructions relating to Isolation and/or Earthing, it must inform the other party. If the change is to make the provisions more stringent, then the other party merely has to note the changes. If the change is to make the provisions less stringent, then the other party needs to approve the new provisions, and the procedures referred to in this OC8.2.3 apply.

OC8.2.3.3 The procedures for the establishment of safety coordination by the GSO with an Interconnected Party are set out in the interconnection operation manual applicable to each Interconnected Party.

OC8.2.4 Safety Coordinators

OC8.2.4.1 For each Grid Supply Point each User will at all times have a person nominated as “Safety Coordinator", to be responsible for the coordination of safety precautions when work is to be carried out on a Network, which necessitates the provision of Safety Precautions on HV Apparatus as required by this OC8. A Safety Coordinator may be responsible for the coordination of safety on HV Apparatus at more than one Grid Supply Point. The names of these Safety Coordinators will be notified in writing to the Network Controller by Users.

OC8.2.4.2 Each Safety Coordinator shall be authorised by the GSO on behalf of the Commission in the case of the Grid Owner or by the Commission in the case of a User, as the case may be, as competent to carry out the functions set out in this OC8 to achieve safety from the Grid System. Only persons with such authorisation will carry out the provisions of this OC8. Each safety coordinator for a User will be a company nominated Commission competent person.

OC8.2.4.3 Contact between Safety Coordinators and the Network Controller will be made via normal operational channels and accordingly separate telephone numbers for Safety Coordinators shall be provided to the Network Controller. At the time of making contact, each User will confirm to the Network Controller that they are authorised to act as Safety Coordinator, pursuant to this OC8.

OC8.2.4.4 If work is to be carried out on a Network which necessitates the provision of Safety Precautions on HV Apparatus in accordance with the provisions of this OC8, the "Requesting Safety Coordinator" who requires the Safety Precautions to be provided will contact the Network Controller who will contact the relevant "Implementing Safety Coordinator" to co-ordinate the establishment of the Safety Precautions.

OC8.2.5 Record of Interconnection of Safety Precautions (RISP)

OC8.2.5.1 This part sets out the procedures for utilising the RISP between Users through the Network Controller.

OC8.2.5.2 The GSO will use the format of the RISP forms set out in Appendix 1 and Appendix 2 to this OC8. The form set out in Appendix 1 and designated as "RISP-A", shall be used when the GSO is the Requesting Safety Coordinator, and the form in Appendix 2, designated as "RISP-B", shall be used when the GSO is the Implementing Safety Coordinator. Proforma of RISP-A and RISP-B will be provided for use by GSO staff.

OC8.2.5.3 Users shall adopt the format of the GSO RISP forms set out in Appendix 1 and Appendix 2 to this OC8.

OC8.2.6 Co-ordination of Work on Apparatus

OC8.2.6.1 Each Party (Requesting) shall notify the other Party (Implementing) by the middle of each month about the work/test that it intends to carry out the following month which will require Isolation and Earthing at the other Party (Implementing)'s System.

OC8.2.6.2 Upon receival of such notice, the Implementing Party shall reply within seven (7) days stating whether such work and/or test can be carried out on the date requested. If not, an alternate date shall be suggested.

OC8.2.6.3 By the end of each month, the GSO will have a programme of scheduled work that is to be carried out that requires the Isolation and/or Earthing of the Grid System and User’s Systems.

OC8.2.6.4 Should an emergency arise that requires work to be done on Apparatus that needs Isolation and/or Earthing to be done on the Grid System and/or User’s Systems, and for which the required notice under this OC8.2.6 cannot be given, then co-ordination can be done via telephone, fax or any other electronic means, but any request and agreement must be confirmed in writing before any work, Isolation or Earthing is carried out.

OC8.2.6.5 Any request and/or agreement related to work/test which will require Isolation and Earthing shall be confirmed in writing prior to its implementation.

OC8.2.6.6 Live Apparatus works shall be subject to the issuance of a live notification.

OC8.3 Safety Precautions for HV Apparatus

OC8.3.1 Agreement of Safety Precautions

OC8.3.1.1 The Requesting Safety Coordinator who requires Safety Precautions on User's System or the Grid System will contact the relevant Implementing Safety Coordinator to give details of the required work location and the requested Isolation point, and to agree the Safety Precautions to be established.

OC8.3.1.2 It is the responsibility of the Implementing Safety Coordinator to ensure that adequate Safety Precautions are established and maintained, on his and/or another System connected to his System, to enable safety from the system to be achieved on the HV Apparatus, specified by the Requesting Safety Coordinator.

OC8.3.1.3 When the Implementing Safety Coordinator is of the reasonable opinion that it is necessary for Safety Precautions on the System of the Requesting Safety Coordinator, other than on the HV Apparatus specified by the Requesting Safety Coordinator, which is to be identified in Part 1.1 of the RISP, he shall contact the Requesting Safety Coordinator and the details shall be recorded in part 1.1 of the RISP forms. In these circumstances it is the responsibility of the Requesting Safety Coordinator to establish and maintain such Safety Precautions.

OC8.3.2 In the Event of Disagreement

OC8.3.2.1 In any case where the Requesting Safety Coordinator and the Implementing Safety Coordinator are unable to agree the Location of the Isolation and (if requested) Earthing, then this shall be at the closest available points on the infeeds to the HV Apparatus on which safety from the Grid System is to be achieved.

OC8.3.3 Implementation of Isolation

OC8.3.3.1 Following the agreement of the Safety Precautions in accordance with OC8.3.1 the Implementing Safety Coordinator shall then establish the agreed Isolation.

OC8.3.3.2 The Implementing Safety Coordinator shall confirm to the Requesting Safety Coordinator that the agreed Isolation has been established and identify the Requesting Safety Coordinator's HV Apparatus up to the Grid Supply Point, for which the Isolation has been provided. The confirmation shall specify:

(a) for each Location, the identity (by means of HV Apparatus name, nomenclature and numbering or position, as applicable) of each point of Isolation;

(b) whether Isolation has been achieved by an Isolating Device in the isolating position or by an adequate physical separation;

(c) where an Isolating Device has been used and whether the isolating position is either:

(i) maintained by immobilising and Locking the Isolating Device in the isolating position and affixing a Caution Notice to it. Where the Isolating Device has been Locked with a Safety Key that the Safety Key has been secured in a Key Safe and the Key-Safe Key will be retained in safe custody; or

(ii) maintained and/or secured by electronic means provided that the entry of at least two (2) passwords are required before an action can be implemented; or

(iii) maintained and/or secured by another method which must be in accordance with the Local Safety Instructions of the GSO or that User, as the case may be; and

(d) where an adequate physical separation has been used that it will be in accordance with, and maintained by, the method set out in the Local Safety Instructions of the GSO or that User, as the case may be, and, if it is a part of that method, that a Caution Notice has been placed at the point of separation.

OC8.3.3.3 The confirmation of Isolation shall be recorded in the respective Switching Operation Record of both the GSO and the User.

OC8.3.4 Implementation of Earthing

OC8.3.4.1 The Implementing Safety Coordinator shall then establish the agreed Earthing.

OC8.3.4.2 The Implementing Safety Coordinator shall confirm to the Requesting Safety Coordinator that the agreed Earthing has been established, and identify the Requesting Safety Coordinator's HV Apparatus up to the Grid Supply Point, for which the Earthing has been provided. The confirmation shall specify:

(a) for each Location, the identity (by means of HV Apparatus name, nomenclature and numbering or position, as is applicable) of each point of Earthing; and

(b) in respect of the Earthing Device used, and whether it is:

(i) immobilised and Locked in the Earthing position. Where the Earthing Device has been Locked with a Safety Key, that the Safety Key has been secured in a Key Safe and the Key-Safe Key will be retained in safe custody; or

(ii) maintained and/or secured by electronic means provided that the entry of at least two (2) passwords are required before an action can be implemented; or

(iii) maintained and/or secured in position by such other method which is in accordance with the Local Safety Instructions of GSO or that User, as the case may be.

The confirmation of Earthing shall be recorded in the respective Switching Operation Record of both the GSO and the User.

OC8.3.4.3 The Implementing Safety Coordinator shall ensure that the established Safety Precautions are maintained until requested to be removed by the relevant

Requesting Safety Coordinator. This request shall follow the cancellation process specified in OC8.3.1.

OC8.3.5 Competencies and Training

OC8.3.5.1 It is the responsibility of the Grid Owner and each User individually to ensure that each member of their respective staffs that will be responsible for implementing any or all of the provisions of this OC8 is fully competent to do so and has been fully trained in all aspects of Safety Co-ordination. Such members of staff shall be authorised by the GSO on behalf of the Commission in the case of the Grid Owner or by the Commission in the case of a User, as the case may be, as competent to carry out the functions set out in this OC8 to achieve safety from the Grid System.

OC8.4 Testing and Re-energisation

OC8.4.1 Testing

OC8.4.1.1 Before any Test can be carried out in part of the System that has been isolated and earthed, the Requesting Party should confirm from the Implementing Party that no person is working or testing or has been authorized to work or test on any part of the System within the points identified on RISP Form.

OC8.4.1.2 Earthing as stated in the RISP Form may be removed during the Test and for testing purposes only. It must be agreed by both parties and properly recorded.

OC8.4.2 Re-energization

OC8.4.2.1 On completion of the work and/or Test, the Requesting Party should contact the Implementing Party to cancel the RISP with the Identifying Number. The Implementing Party should read out Parts 1.1 and 1.2 of the said RISP. The Requesting Party should confirm that Parts 1.1 and 1.2 of his RISP are the same. Requesting Party should then cancel the form by signing Part 3 and the Implementing Party will then confirm the cancellation by signing Part 3.

OC8.4.2.2 Re-energization shall be carried out in accordance with the following procedure:

(a) The switching sequence for normalization of the System should be carried as listed in the switching form.

(b) All switching done should be written down and repeated to the other Party who should then read back for confirmation.

(c) All switching done should be recorded in chronological order.

<End of the Operating Code No.8: Safety Coordination>

Operating Code 8 - Appendix 1 – RISP – A

RECORD OF INTERCONNECTION OF SAFETY PRECAUTIONS (RISP- A)

RISP A No: **RISP B No:**

(Requesting Safety Coordinator's Copy) (Implementing Safety Coordinators)

Part 1

1.1 HV APPARATUS IDENTIFICATION

1.2 I, ………………………………………………………………… (the Requesting Safety Coordinator) located at ....…………… declare that I would like to carry out work on the following Apparatus:
....……………………
…………………………………………………………………

1.3 Mr/Ms/Mrs ………………………………………………………… (the Implementing Safety Coordinator) has declared that he will carry out work on the following Apparatus……...……
……………………………………………………………

1.4 Safety Precautions established by the Requesting Safety Coordinator:

State location, nomenclature, and number of each point of isolation and earthing to be implemented.

ISOLATION:
…………………………………………………………………………………………………

EARTHING:
……………………………………………………………………………………………………

1.5 SAFETY PRECAUTIONS REQUESTED BY THE REQUESTING SAFETY COORDINATOR ISOLATION :

State location, nomenclature, and number of each point of isolation requested.

ISOLATION:
……………………………………………………………………………………………………

EARTHING:
……………………………………………………………………………………………………

Signed: .... Date:..............................
Time:...............................

The Requesting Safety Coordinator.

Part 2

2.1 CONFIRMATION OF ISOLATION AND EARTHING BY REQUESTING SAFETY COORDINATOR AND IMPLEMENTING SAFETY COORDINATOR.

2.2 I, ...…………....................................... (the Requesting Safety Coordinator), located at ....…………………… confirm to ………………………………………………………… (the Implementing Safety Coordinator) located at ………………………………………………….. that the SAFETY PRECAUTION as mentioned in Section 1.4 of this RISP **has been established.** The switches have been immobilized, locked and notices have been affixed.

2.3 Mr/Ms/Mrs .... (the Implementing Safety Coordinator), located at.. has confirmed to me that the SAFETY PRECAUTIONS as mentioned in section 1.5 **has been established**. The switches have been immobilized, locked, and notices have been affixed. No instructions will be issued at locations as specified in 1.4 and 1.5 for their removal until this RISP is cancelled under Part 3.

Signed: .... Date :......................…….................

Time:.........................

The Requesting Safety Coordinator.

Part 3

3.1 CANCELLATION

Cancellation of this RISP must only be done after both parties have confirmed completion of work as mentioned in Section 1.2 and 1.3.

3.2 I, ……………………………………………………………… (the Requesting Safety Coordinator), located at ……………………………………....... declared that the work as mentioned in Section 1.2 is completed.

Signed : ....…….. Date : ....……………….

Time:...................................

The Requesting Safety Coordinator.

3.3 Mr/Ms/Mrs ……………………………………………… (the Implementing Safety Coordinator), located at ……………………………………, has confirmed that the work as mentioned as Section 1.3 is complete.

Signed : ....… Date : ....………………

Time:....................................

The Requesting Safety Coordinator.

3.4 I, ……………………………………………………………… (the Requesting Safety Coordinator), located at ……………………………………………………… and Mr/Ms/Mrs ……………………………………………… (the Implementing Safety Coordinator), located at …………………………………… agree that this RISP is hereby cancelled.

Signed:...…… Date: ……………………………………

Time:..….

The Requesting Safety Coordinator.

<End of the Operating Code No.8: Safety Coordination – Appendix 1>

Operating Code 8 - Appendix 2 – RISP – B

RECORD OF INTERCONNECTION OF SAFETY PRECAUTIONS (RISP –B)

RISP-B No: **RISP A No:**

(Implementing Safety Coordinator's Copy) (Requesting Safety Coordinators)

Part 1

1.1 HV APPARATUS IDENTIFICATION

1.2 Mr/Ms/Mrs, ...……………… (the Requesting Safety Coordinator) located at ....……………… declare that he would like to carry out work on the following Apparatus: ....…………………… ………………………………………………………….

1.3 I, ……………………………………………………………… (the Implementing Safety Coordinator) has declared that I will carry out work on the following Apparatus………………………………………………………………………………………………………...……. ……………………………………………………………

1.5 SAFETY PRECAUTIONS ESTABLISHED BY THE REQUESTING SAFETY COORDINATOR :

State location, nomenclature, and number of each point of isolation and earthing to be implemented.

ISOLATION:

…………………………………………………………………………………………

EARTHING:

…………………………………………………………………………………………

1.6 SAFETY PRECAUTIONS REQUESTED BY THE REQUESTING SAFETY COORDINATOR ISOLATION :

State location, nomenclature, and number of each point of isolation requested.

ISOLATION:

…………………………………………………………………………………………

EARTHING:

…………………………………………………………………………………………

Signed:……….. Date:...

Time: ....

The Implementing Safety Coordinator.

Part 2

2.1 CONFIRMATION OF ISOLATION AND EARTHING BY REQUESTING SAFETY COORDINATOR AND IMPLEMENTING SAFETY COORDINATOR.

2.2 Mr/Ms/Mrs, ………………………………………………… (the Requesting Safety Coordinator), located at ……………………………… has confirmed to me ……………………………………………………………… (the Implementing Safety Coordinator) located at ……………………………that the SAFETY PRECAUTION as mentioned in Section 1.4 of this RISP **has been established.** The switches have been immobilised, locked and Notices have been affixed.

2.3 I, ………………………………………………………………………… (the Implementing Safety Coordinator), located at ……………………………………………… have confirmed to Mr/Ms/Mrs ……………………………………………………….. (the Requesting Safety Coordinator), located at…………………………………… that the SAFETY PRECAUTIONS as mentioned in section 1.5 **has been established**. The switches have been immobilized, locked, and notices have been affixed. No instructions will be issued at locations as specified in 1.4 and 1.5 for their removal until this RISP is cancelled under Part 3.

Signed: …………………………………… Date :……………………………………
Time:…………………
The Implementing Safety Coordinator.

Part 3

3.1 CANCELLATION

Cancellation of this RISP must only be done after both parties have confirmed completion of work as mentioned in Section 1.2 and 1.3.

3.2 Mr/Ms/Mrs, ………………………………………………….. (the Requesting Safety Coordinator), located at …………………………………….......................... has confirmed that the work as mentioned in Section 1.2 is completed.

Signed : ....…….. Date : ....…………..
Time:.....................................
The Implementing Safety Coordinator.

3.3 I, ……………………………………………………………………. (the Implementing Safety Coordinator), located at …………………………………………………, has confirm that the work as mentioned as Section 1.3 is complete.

Signed : .... Date : ....……
Time:.....................................
The Implementing Safety Coordinator.

3.4 Mr/Ms/Mrs, ………………………………………………… (the Requesting Safety Coordinator), located at …………………………………………………………. and I, …………………………………………………………… (the Implementing Safety Coordinator), located at ……………………………………… agree that this RISP is hereby cancelled.

Signed:.................................……………….. Date:………………………………………
Time:.....................................…..
The Implementing Safety Coordinator.

<End of the Operating Code No.8: Safety Coordination – Appendix 2>

Operating Code No.9 (OC9): Numbering and Nomenclature

OC9.1 Introduction, Objectives and Scope

OC9.1.1 The provisions of sections MOC9.1, MOC9.2 and MOC9.3 of the Main Code shall apply to this Operating Code No.9: Numbering and Nomenclature.

OC9.2 Procedure

OC9.2.1 General

OC9.2.1.1 The term "User Site" means a site owned (or occupied pursuant to a lease, licence or other agreement) by a User in which there is a Grid Supply Point. For the avoidance of doubt, where a site is owned by the Grid Owner but occupied by another User, the site is a User Site.

OC9.2.1.2 The term "Site of the Grid Owner" means a site owned (or occupied pursuant to a lease, licence or other agreement) by the Grid Owner in which there is a Grid Supply Point. For the avoidance of doubt, where a site is owned by a User but occupied by the Grid Owner, the site is Site of the Grid Owner.

OC9.2.2 Grid Owner HV Apparatus

OC9.2.2.1 HV Apparatus of the Grid Owner on the Grid Owner Sites shall have numbering and nomenclature in accordance with the system used by the GSO.

OC9.2.2.2 HV Apparatus of the Grid Owner on User's Sites shall have numbering and nomenclature in accordance with the system used by the GSO. For the Grid System and at points of interface between the Grid System and a User's system it is the responsibility of the GSO to determine the numbering and nomenclature convention which Users shall follow.

OC9.2.2.3 Due to system changes, although the naming and nomenclature convention will remain unchanged, the names and numbers of individual items of apparatus and equipment may change from time to time. Users and the GSO, as the case may be, should be aware of this and take all reasonable measures to ensure that labels and Single Line Diagrams are maintained in accordance with the most recent names and numbers. If there are changes in system arrangements that affect names and numbering, naming and numbering of User's equipment shall be changed as required by the GSO.

OC9.2.2.4 The GSO may, in certain circumstances, provide temporary names and numbers for equipment and apparatus to Users. Where this is the case, the GSO shall declare the names and/or numbers as temporary. The relevant User will not install, or permit the installation of, any HV Apparatus on such User Site which has numbering and/oror nomenclature which could be confused with HV Apparatus of the Grid Owner which is either already on that User Site or which the Grid Owner has notified that User will be installed on that User Site.

OC9.2.3 User HV Apparatus on Grid Owner Sites

OC9.2.3.1 User's HV Apparatus on Sites of the Grid Owner shall have numbering and nomenclature in accordance with the system specified by the GSO.

OC9.2.3.2 When a User is to install its HV Apparatus on a Site of the Grid Owner, or it wishes to replace existing HV Apparatus on a Site of the Grid Owner and it wishes to adopt new numbering and nomenclature for such HV Apparatus, the User shall notify the GSO of the details of the HV Apparatus and the User shall request a proposed numbering and nomenclature to be adopted for that HV Apparatus from the GSO, at least eight (8) months prior to proposed installation.

OC9.2.3.3 The notification will be made in writing to the GSO and shall consist of a proposed Operation Diagram incorporating the proposed new HV Apparatus of the User to be installed.

OC9.2.3.4 The GSO will respond in writing to the User within two (2) months and provide details of the numbering and nomenclature which the User shall adopt for that

HV Apparatus. The User shall then inform any other effected or related User and shall adopt the numbering and nomenclature within six (6) months of the details being provided by the GSO.

OC9.2.4 Changes

OC9.2.4.1 Where the GSO in its reasonable opinion has decided that it needs to change the existing numbering or nomenclature of HV Apparatus of the Grid Owner on other User's Site or of User's HV Apparatus on a Site of the Grid Owner:

(a) the provisions of paragraph OC9.2.2 shall apply to such change of numbering or nomenclature of HV Apparatus of the Grid Owner with any necessary amendments to those provisions to reflect that only a change is being made; and

(b) in the case of a change in the numbering or nomenclature of User's HV Apparatus on a Site of the Grid Owner, the GSO will notify the User of the numbering and/or nomenclature the User shall adopt for that HV Apparatus (the notification to be in a form similar to that envisaged under OC9.2.2) at least eight (8) months prior to the change being needed and the User will respond in writing to the GSO within two (2) months of the receipt of the notification, confirming receipt. The User shall then inform any other effected or related User and shall adopt the numbering and nomenclature within six (6) months of the details being provided by the GSO.

OC9.2.4.2 Users will be provided upon request with details of the current numbering and nomenclature system of the Grid in order to assist them in planning the numbering and nomenclature for their HV Apparatus on Sites of the Grid Owner.

OC9.2.4.3 When either the Grid Owner or other User installs HV Apparatus which is the subject of OC9, the Grid Owner or other User, as the case may be, shall be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature.

OC9.2.4.4 Where a User is required by OC9 to change the numbering and/or nomenclature of HV Apparatus which is the subject of OC9, the User will be responsible for the provision and erection of clear and unambiguous labelling by the required date.

OC9.2.4.5 Where the Grid Owner changes the numbering and/or nomenclature of its HV Apparatus which is the subject of OC9, the Grid Owner will be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature by the required date.

OC9.2.4.6 The GSO will not change its system of numbering and nomenclature in use other than to reflect new or newly adopted technology or HV Apparatus.

<End of the Operating Code No.9: Numbering and Nomenclature>

Operating Code No.10 (OC10): Periodic Testing and Supervising

OC10.1 Introduction, Objectives and Scope

OC10.1.1 The provisions of sections MOC10.1, MOC10.2 and MOC10.3 of the Main Code shall apply to this Operating Code No.10: Periodic Testing and Supervising.

OC10.2 Procedure for Supervising

OC10.2.1 The GSO will supervise the performance of:

(a) compliance by Users with the CC; and

(b) the provision by Users of Ancillary Services and other parameters which they are required or have agreed to provide under the relevant Agreements.

OC10.2.2 If in the reasonable view of the GSO, a Generator or an Energy Storage Operator or an Aggregator has failed to comply with the requirements provisioned by the CC, the GSO shall notify the relevant Generator or Energy Storage Operator or Aggregator or User and Single Buyer, giving details of the failure and the circumstances.

OC10.2.3 If in the reasonable view of the GSO, a Generator or User has failed to provide the Ancillary Services and other parameters required or has agreed to provide under relevant Agreement, the GSO shall notify the relevant Generator or User and the Single Buyer, giving details of the failure and the circumstances.

OC10.2.4 The relevant Generator or User, as the case may be, will, as soon as possible, provide the GSO and the Single Buyer with an explanation of the reasons for the failure and, in the case of a Generator, details of the action that it proposes to take to enable the Generator or User to meet those parameters and or the requirements to provide the Ancillary Services required or the Ancillary Services it has agreed to provide, within a reasonable period.

OC10.2.5 The GSO, the Single Buyer and the Generator or User, as the case may be, will then discuss the action that, in the case of a Generator, the Generator proposes to take and will endeavour to reach agreement as to the parameters which are to apply to the Dispatch Unit and the effective date(s) for the application of the agreed parameters and, in the case of a User, that the User proposes to take.

OC10.2.6 Unless otherwise provided in the relevant Agreements, in the event that agreement on the parameters cannot be reached within fourteen (14) days of notification of the non-compliance by the GSO to the Generator, a re-test shall be required and should be facilitated by the GSO.

OC10.2.7 From time to time, especially following major disturbance in the Grid System, if non-performance identified, the GSO shall request from the user to carry out the test relevant to the non-performance and the user shall comply as set out in OC10.3.

OC10.2.8 The GSO will favour continuous supervising over testing to ensure compliance of Users. Frequency response, Reactive Power or PSS to damp out oscillation shall be supervised based on data acquired from SCADA and/or WAMS and/or meters.

OC10.3 Procedure for Periodic Testing

OC10.3.1 General

OC10.3.1.1 The GSO will notify a Generator with Generating Modules that it proposes to carry out any relevant tests at least two (2) Business Days prior to the time of the proposed test. The GSO will only make such a notification if the relevant Generator has declared the relevant Generating Module available in an Availability declaration in accordance with SDC1 at the time the notification is issued. If the GSO makes such a notification, the relevant Generator shall then be obliged to make that Generating Module available for the time and for the duration that the test is instructed to be carried out, unless that Generating Module would not be available by reason of a planned outage approved prior to this instruction in accordance with OC2.

OC10.3.1.2 For tests which are required under relevant Agreements, the GSO and the Single Buyer will make notification to a Generator in accordance with procedures stated in the relevant Agreements.

OC10.3.1.3 Any testing to be carried out is subject to Grid System conditions prevailing on the day.

OC10.3.2 List of Periodic Tests

The following is the list of periodic tests under OC10. Notwithstanding that, all the tests performed during commissioning and described under CC8.4 can be requested during operation;

(a) Reactive Power Tests—

(i) are stated under CC8.4.2

(ii) shall be carried out at least once in every five (5) years or as and when required by the GSO and the Single Buyer;

(b) Frequency Response Tests—

(i) are stated under CC8.4.3

(ii) shall be carried out as and when they are required by the GSO and the Single Buyer

(c) House Load Tests—

(i) are stated under CC8.4.5

(ii) shall be carried out at least once every three (3) years. Where possible such tests should be arranged to coincide with the departure to a major scheduled maintenance of the Generating Unit.

(d) Black Start Tests—

(i) are stated under CC8.4.4

(ii) shall be carried out at least once every three (3) years. Where possible such tests should be arranged to coincide with the return to service of a Generating Unit following a major overhaul or a major scheduled maintenance programme.

(e) PSS Tests

PSS settings and damping are part of technical requirements imposed on Generators and the Grid Owner. The GSO and the Grid Owner has the responsibility to ensure that the PSS is functioning correctly and is optimally tuned to damp out local and inter area oscillation modes according to CC6.4.4.10. Studies and testing of PSS controllers will be carried out periodically by the Generators for every 5 years or whenever there is any significant network change in the system, advised by GSO.

OC10.3.3 Monitoring Tests

OC10.3.3.1 The GSO shall facilitate Monitoring Tests whenever required to do so by the Single Buyer, and the GSO shall report to the Single Buyer the outcome of test conducted.

OC10.3.4 Test Reporting Requirements

OC10.3.4.1 Subject to passing a test, a Preliminary Report of a Periodic Test shall be submitted by the Generator within seventy-two (72) hours after the completion of the test and a Final Report within thirty (30) days by the Generator unless different periods have been agreed to by the GSO, and the Generator.

OC10.3.4.2 The Final Report shall include a description of the Plant and/or Apparatus tested, the date of the test and a description of the System Test carried out, together with the results, conclusions and recommendations.

OC10.3.4.3 The GSO shall confirm acceptance of the final report as a true and accurate record of the test within seven (7) days of receipt of the final report. Whenever Monitoring Tests are concerned, reference should be made to existing relevant Agreement for acceptance of Final Report.

OC10.4 Failure of Tests

OC10.4.1 In the case where a Generator fails to pass the required test as specified by this OC10, the Generator shall provide clarifications for each failed test clarifying the causes for such failure or non-compliance and the remedial actions to be taken. The Generator shall undertake any necessary rectification of its plant or equipment to be capable of meeting the requirements and consult the GSO to schedule a re-test.

OC10.4.2 If in the case where a Generator fails to pass the re-test, the GSO shall notify in writing within five (5) Business Days of the test to the concerned Generator, the Single Buyer and the Commission where necessary, providing details of the non-compliance and or limitations including the implications of the non-compliance and or the limitations.

OC10.4.3 The provisions of the relevant Agreements shall apply for failure of tests thereunder.

OC10.4.4 In cases for which there are no provisions in the relevant Agreements and if a dispute arises relating to the failure, the GSO and the relevant parties shall seek to resolve the dispute by discussion, and, if they fail to reach an agreement, the GSO reserves the right to request User to re-test following the procedure set out in the relevant section of OC10.3.

OC10.4.5 If the Generator concerned fails to pass the re-test and a dispute arises from that re-test, either party may use the relevant Agreement dispute resolution procedure. If there is no such provision in the relevant Agreement, then the Grid Code dispute resolution procedure, contained in the General Conditions (GC), for a ruling in relation to the dispute, shall be applied.

OC10.4.6 If it is accepted that the Generator has failed the test or re-test (as applicable), the Generator shall within fourteen (14) Business Day or as per the relevant Agreements as the case may be, submit in writing to the GSO for the approval of the date and time by which the Generator shall have rectified the non-compliance concerned to a condition where it complies with the relevant requirements set out in the PC, CC or SDC and would pass the test. The GSO will not unreasonably withhold or delay its approval of the Generator's proposed date and time submitted. The Generator shall then be subjected to the relevant test procedures outlined in OC10.3.

OC10.5 Procedure for on-site investigation

OC10.5.1 If in the reasonable view of the Grid Owner, there may be an issue of non-compliance by a User at the Grid entry point, the Grid Owner may carry out an investigation on site to check compliance of User's Installation with the Grid Code and or other relevant agreements.

OC10.5.2 The Grid Owner shall notify the concerned User and the GSO at least two (2) Business Days prior to the date of the on-site investigation. The GSO shall advise the suitable time for such test, base on Grid System condition.

<End of the Operating Code No.10: Periodic Testing and Supervising>

Operating Code No.11 (OC11): System Tests

OC11.1 Introduction, Objectives and Scope

OC11.1.1 The provisions of sections MOC11.1, MOC11.2 and MOC11.3 of the Main Code shall apply to this Operating Code No.11: System Tests.

OC11.2 Procedure for Arranging System Tests

OC11.2.1 General

OC11.2.1.1 System Tests which in the reasonable opinion of the GSO are expected to have a "minimal effect" upon the Grid System and/or User Systems will not be subject to this procedure. "Minimal effect" means that any distortion to voltage and Frequency at Grid Supply Points does not exceed the License Standards and that the security of the Grid System is not compromised.

OC11.2.1.2 Where a System Test is proposed by a User and considered by that User to have a "minimal effect" upon the Grid System and/or the User System, it is the responsibility of that User to determine that this is the case and if in doubt, to consult the GSO.

OC11.2.1.3 Where the System Test is proposed by the GSO, it is the responsibility of the GSO to determine whether or not the System Test will have “minimal effect” upon the Grid System and User’s Systems.

OC11.2.2 Test Proposal Notice

OC11.2.2.1 The level of Demand on the Grid System varies substantially according to the time of day and less so according to the time of year. Consequently, certain System Tests which may have a significant impact on the Grid System (for example, tests of the full load capability of a Generating Unit over a period of several hours) can only be undertaken at certain times of the day and year. Other System Tests, for example, those involving substantial MVAr generation or valve tests, may also be subject to timing constraints. It therefore follows that notice of System Tests should be given as far in advance of the date on which they are proposed to be carried out as reasonably practicable, and in any case not less than three (3) months prior to the proposed date of the System Tests.

OC11.2.2.2 In certain cases a System Test may need to be conducted in less than three (3) months' notice. In that case, after consultation with the Test Proposer and User(s) identified by the GSO under MOC11.3, the GSO shall propose a suitable timetable for the System Test and the procedure set out in OC11.2.3 to OC11.2.6 shall be followed in accordance with that timetable.

OC11.2.2.3 When the Grid Owner or any other User intends to undertake a System Test, a "Test Proposal Notice" shall be given by the "Test Proposer" to the GSO and to all parties who may be affected by such a test. The proposed Test Proposal Notice shall be in writing and include details of the nature and purpose of the test and will indicate the extent and situation of the Plant and Apparatus involved. The proposal shall also include the detailed test procedures.

OC11.2.2.4 If the GSO is of the view that the information set out in the Test Proposal Notice is insufficient, it will contact the Test Proposer as soon as reasonably practicable. The GSO will not be required to do anything under this OC11 until it is satisfied with the details supplied in the Test Proposal Notice or pursuant to a request for further information.

OC11.2.2.5 Each User including the Grid Owner must submit a Test Proposal Notice to the GSO if it proposes to undertake a System Test. Examples of System Tests that a User may carry out are as follows:

(a) Generating Module full load capability tests including load acceptance tests and re-commissioning tests;

(b) Var limiter tests;

(c) Main steam valve tests;

(d) Load rejection tests;

(e) On-load protection testing;

(f) Directional tests;

(g) Primary Response and Secondary Response performance tests;

(h) Short-circuit generator terminal test; and

(i) Special Protection Scheme tests.

OC11.2.2.6 If the GSO wishes to undertake a System Test, the GSO shall be deemed to have written a proposal of that test through procedures internal to the GSO. Examples of System Tests that the GSO may carry out are as follows:

(a) Load rejection tests;

(b) Directional tests;

(c) Special Protection Scheme tests;

(d) Test involving changes in Grid System impedances; and

(e) Island Restoration Plan or Emergency Restoration Plan test.

OC11.2.2.7 The GSO shall have overall co-ordination of any System Test, using the information provided to it under this OC11.2.2 and shall identify in its reasonable estimations, which Users other than the Test Proposer or which other Users not already identified by the Test Proposer, may be affected by the System Test.

OC11.2.3 Pre-System Test Arrangements

Following receipt of the Test Proposal Notice, the GSO shall evaluate and discuss the proposal with the affected identified Users.

OC11.2.3.1 The GSO shall arrange a meeting or meetings to discuss the following with the Test Proposer and affected Users:

(a) the details of the nature and purpose of the proposed System Test and other matters set out in the Test Proposal Notice (together with any further information requested by the GSO under OC11.2.2;

(b) the economic, operational and risk implications of the proposed System Test;

(c) 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 GSO and Users; and

(d) implications of the proposed System Test on the Scheduling and Dispatch of Power Station or Energy Storage Unit, in so far as it is able to do so.

OC11.2.3.2 Users identified by the GSO under MOC11.3 and the Test Proposer shall provide to the GSO, upon written request, as many details as the GSO reasonably requires in order to review the proposed System Test.

OC11.2.3.3 The number of meetings will be decided by the GSO as he deems necessary to conduct the proposed System Test.

OC11.2.4 Test Programme

OC11.2.4.1 If the System Test is allowed to proceed, at least one (1) month prior to the date of the proposed System Test, the Test Proposer will submit to the GSO and each User identified by the GSO under MOC11.3, a proposed Test Programme stating the procedure detailing the pre-requisites for the System Test, the different steps for carrying out the System Test including the manner in which it is to be monitored, a list of those staff involved in carrying out the System Test (including those responsible for site safety) and such other matters as the GSO deems appropriate. The proposed Test Programme shall be reviewed and agreed by the GSO at least two (2) weeks prior to the date of the proposed System Test.

OC11.2.4.2 The Test Programme will bind all recipients to act in accordance with the provisions of the Test Programme in relation to the proposed System Test subject to the following paragraph.

OC11.2.4.3 Any problems with the proposed System Test which arise or are anticipated after the issue of the Test Programme and prior to the day of the proposed System Test, must be notified to the GSO as soon as possible in writing. If the GSO decides that these anticipated problems merit an amendment to, or postponement of, the System Test, the GSO shall notify the Test Proposer (if the Test Proposer is not the GSO) and each User identified accordingly under MOC11.3 by the GSO.

OC11.2.4.4 If on the day of the proposed System Test, operating conditions on the Power 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 GSO of this decision and the reasons for it. The GSO shall then postpone or cancel, as the case may be, the System Test and shall, if possible, agree another suitable time and date after discussion with the Test Proposer (if the Test Proposer is not the GSO) and all Users identified by the GSO under MOC11.3.

OC11.2.5 Post System Test Report

OC11.2.5.1 Preliminary Report of a System Test shall be submitted by the Test Proposer within seventy-two (72) hours after the completion of the test and a Final Report within sixty (60) days by the Test Proposer unless different periods have been agreed to by the GSO and the test Proposer.

OC11.2.5.2 The Final Report shall include a description of the Plant and/or Apparatus tested, the date of the test and a description of the System Test carried out, together with the results, conclusions and recommendations.

OC11.2.5.3 The GSO and/or Grid Owner, as the case may be, shall confirm acceptance of the final report as a true and accurate record of the test within seven (7) days of receipt of the final report.

<End of the Operating Code No 11: System Tests>`

<End of the Operating Code >

Scheduling and Dispatch Code (SDC)

SDC.1 Preamble

SDC.1.1 The Grid Code is a a code developed and issued by the Commission. The Grid Code is composed by a Main Code, containing the main provisions structuring the purpose, the scope, the governance and some general requirements, and by additional codes, containing the specific technical rules for different subjects related to the operation of the Grid system.

SDC.1.2 According to section 50A of the Electricity Supply Act 1990 [*Act 447*], the Commission may develop and issue such additional codes as it deems fit and expedient or the Minister may direct from time to time, as the case may be.

SDC.2 Amendment

SDC.2.1 The Commission may at any time amend, modify, vary or revoke this Code or any part thereof.

Scheduling and Dispatch Code No.1 (SDC1): Unit Scheduling

SDC1.1 Introduction, Objectives and Scope

SDC.1.1 The provisions of sections MSDC1.1, MSDC1.2 and MSDC1.3 of the Main Code shall apply to this Scheduling and Dispatch Code No1.

SDC1.2 Procedure

SDC1.2.1 Applicability

SDC1.2.1.1 Schedules and other information supplied by the Single Buyer to the User, or Declarations and other information supplied by the User including generators participating in TPA to the Single Buyer, as the case may be, under this SDC1 shall be supplied on the current Working Day for the following Working Day.

SDC1.2.1.2 Where the day following the current Working Day is a Non-Working Day, Schedules and other information supplied by the Single Buyer to the User, or Declarations and other information supplied by the User to the Single Buyer, as the case may be, under this SDC1 shall be supplied on the current Working Day for each of the two (2) days following the current Working Day.

SDC1.2.1.3 Where there are several consecutive days following the current Working Day that are Non-Working Days, Schedules and other information supplied by the Single Buyer to the User, or Declarations and other information supplied by the User to the Single Buyer, as the case may be, under this SDC1 shall be supplied on the current Working Day for each of the consecutive Non-Working Days and for the day following the period of consecutive Non-Working days, except as required under SDC1.2.1.4.

SDC1.2.1.4 Where there are more than four (4) consecutive Non-Working Days following the current Working Day, Schedules and other information supplied by the Single Buyer to the User, or Declarations and other information supplied by the User to the Single Buyer, as the case may be, under this SDC1 shall be supplied on the current Working Day for each of the next four (4) consecutive Non-Working Days and for the day following the period of four (4) consecutive Non-Working days.

SDC1.2.1.5 If SDC1.2.1.4 applies, Schedules and other information supplied by the Single Buyer to the User, or Declarations and other information supplied by the User to the Single Buyer, as the case may be, under this SDC1 shall be supplied on the day immediately following the period of four (4) consecutive Non-Working days, whether or not it is a Working Day, for the following day.

SDC1.2.2 User Availability Declaration

SDC1.2.2.1 By 1000 hours each Working Day each Generator shall in respect of each of its CDGUs submit to the Single Buyer in writing (or by such electronic data transmission facilities as have been agreed with the Single Buyer) an Availability Declaration stating whether or not such CDGU is proposed by that Generator to be available for generation and ancillary services in respect of the next following period from 0000 hours to 2400 hours for each day. If it is available it must state the Declared Availability expressed in a whole number of MW, in respect of any time period during the following day or days specifying the time at which each time period begins and finishes, and the other data listed under DRC8.1. Such Availability Declaration will replace any previous Availability Declaration covering any part of the next following Availability Declaration period. In so far as not revised, the previously submitted Availability Declaration shall apply for the next following Availability Declaration period.

SDC1.2.2.2 Data requirements include, in the case of CCGT Modules, the CCGT Module Matrix which shows the combination of CCGT Units running in relation to any given MW output, in the form of the diagram illustrated in DRC8.1. The CCGT Module Matrix is designed to achieve certainty by knowing the number of CCGT Units to be synchronized to achieve a Dispatch Instruction.

SDC1.2.2.3 The other data may also include in the case of a Range CCGT Module, a request for the Connection Point at which the power is provided from the Range CCGT Module to be changed with effect from the beginning of the following

Schedule Day to another specified single Connection Point (there can be only one) to that being used for the current Schedule Day. The Single Buyer will respond to this request at the same time that it issues the Least Cost Unit Schedule. If the Single Buyer agrees to the request (such Agreement not to be unreasonably withheld), the Generator will operate the Range CCGT Module in accordance with the request. If the Single Buyer does not agree, the Generator will, if it produces power from that Range CCGT Module, continue to provide power from the Range CCGT Module to the Connection Point being used at the time of the request. The request can only be made up to 1000 hours in respect of the following Schedule Day. No subsequent request to change can be made after 1000 hours in respect of the following Schedule Day.

SDC1.2.2.4 The principles set out in DRC8.1 apply to the submission of a CCGT Module Matrix and accordingly the CCGT Module Matrix can only be amended as follows:

(a) Normal CCGT Module

if the CCGT Module is a Normal CCGT Module, the CCGT Units within that CCGT Module can only be amended such that the CCGT Module comprises different CCGT Units if the Single Buyer gives its prior consent in writing and is also consistent with the relevant Agreement. Notice of the wish to amend the CCGT Units within such a CCGT Module must be given at least six (6) months before it is wished for the amendment to take effect; or

(b) Range CCGT Module

if the CCGT Module is a Range CCGT Module, the CCGT Units within that CCGT Module can only be amended such that the CCGT Module comprises different CCGT Units for a particular Schedule Day if the relevant notification is given by 1000 hours on the day prior to the Schedule Day in which the amendment is to take effect. No subsequent amendment may be made to the CCGT Units comprising the CCGT Module in respect of that particular Schedule Day.

SDC1.2.2.5 In the absence of the submission of a CCGT Module Matrix, the last correctly submitted CCGT Module Matrix shall be deemed the CCGT Module Matrix.

SDC1.2.2.6 In the case of a CCGT Module Matrix submitted or deemed to be submitted as part of the other data for CCGT Modules, the output of the CCGT Module at any given instructed MW output must reflect the details given in the CCGT Module Matrix. It is accepted that in cases of change in MW in response to Dispatch Instruction issued by the GSO there may be a transitional variance to the conditions reflected in the CCGT Module Matrix. In achieving a Dispatch Instruction, the range of number of CCGT Units envisaged in moving from one MW output level to the other must not be departed from. Each Generator shall notify the GSO as soon as practicable after the event of any such variance.

SDC1.2.2.7 Subject as provided above, the GSO will rely on the CCGT Units specified in such Matrix running as indicated in the CCGT Module Matrix when it issues a Dispatch Instruction in respect of the CCGT Module.

SDC1.2.2.8 Any changes to the CCGT Module Matrix must be notified immediately to the Single Buyer in accordance with the provisions of SDC1 and relevant Agreement. Such Availability Declaration will replace any previous Availability Declaration covering any part of the next following Availability Declaration Period.

SDC1.2.2.9 A revised Availability Declaration may be made in respect of any CDGU which, since the time at which the Availability Declaration relating to that CDGU, or any previous revised Availability Declaration under this section, was prepared, has either:

(a) become available at a different wattage to that which such CDGU was proposed to be made available for generation in any such Availability Declaration whether higher or lower (including zero); or

(b) in the case of a CDGU declared to be not available for generation in an Availability Declaration become available for generation.

SDC1.2.2.10 The revisions to the other data are listed under the Availability Declaration heading in DRC8.1.

SDC1.2.2.11 A revised Availability Declaration submitted by a Generator under this paragraph shall state, in respect of any CDGU whose availability for generation is revised, the time periods specifying the time at which each time period begins and finishes in the relevant Availability Declaration period in which said CDGU is proposed to be available for generation and, if such CDGU is available, at what wattage, expressed in a whole number of MW, and what limits for Ancillary Services, in respect of each such time period.

SDC1.2.2.12 In the case of Power Park Modules (PPM), the Power Park Module Matrix which shows the combination of Power Park Units running in relation to any given MW output and shall be prepared in accordance with Good Industry Practice and approved by GSO. The Power Park Module Matrix is in the form of the example illustrated in DRC8.1. The Power Park Module Matrix is designed to achieve certainty in knowing the number of Power Park Units synchronized to achieve a Dispatch. The GSO and the Single Buyer will rely on the Power Park Units and Power Park Modules of each Power Station specified in such Power Park Module Availability Matrix running as indicated in the Power Park Module Availability Matrix when it issues an instruction in respect of the Power Station instruction.

SDC1.2.2.13 By 1000 hours each Working Day each Energy Storage Operator shall submit to the Single Buyer in writing or via such electronic data transmission facilities as agreed upon with the Single Buyer, an Availability Declaration stating whether or not it is proposed to be available for import or export of energy and provision of Ancillary Services in respect of the next following period from 0000 hours to 2400 hours for each day. If it is available it must state the Declared Availability expressed in a whole number of MW, in respect of any time period during the following day or days specifying the time at which each time period begins and finishes. Such Availability Declaration will replace any previous Availability Declaration covering any part of the next following Availability Declaration period. In so far as not revised, the previously submitted Availability Declaration shall apply for the next following Availability Declaration period.

SDC1.2.2.14 A revised Availability Declaration may be made in respect of any Energy Storage Unit which, since the time at which the Availability Declaration relating to that Energy Storage Unit, or any previous revised Availability Declaration under this section, was prepared, has either:

(a) become available at a different wattage to that which such Energy Storage Unit was proposed to be made available in any such Availability Declaration whether higher or lower (including zero); or

(b) become available in the case of an Energy Storage Unit declared to be not available in an Availability Declaration.

This revised Availability Declaration shall state the time periods specifying the time at which each time period begins and finishes in the relevant Availability Declaration period in which such Energy Storage Unit is proposed to be available and at what wattage, expressed in a whole number of MW, and what limits for Ancillary Services, in respect of each such time period.

SDC1.2.2.15 By 1000 hours each Working Day each Aggregator shall submit to the Single Buyer in writing (or by such electronic data transmission facilities as agreed upon with the Single Buyer) an Availability Declaration stating whether it is proposed to be available in respect of the next following period from 0000 hours to 2400 hours for each day. If it is available, it must state the Declared Availability expressed in a whole number of MW, in respect of any time period during the following day or days specifying the time at which each time period begins and finishes. Such Availability Declaration will replace any previous Availability Declaration covering any part of the next following Availability Declaration period. In so far as not revised, the previously submitted Availability Declaration shall apply for the next following Availability Declaration period.

SDC1.2.2.16 A revised Availability Declaration may be made in respect of any Aggregator which, since the time at which the Availability Declaration relating to that Aggregator, or any previous revised Availability Declaration under this section, was prepared, has either:

(a) become available at a different wattage to that which such Aggregator was proposed to be made available in any such Availability Declaration whether higher or lower (including zero); or

(b) become available in the case of an Aggregator declared to be not available in an Availability Declaration.

This revised Availability Declaration shall state the time periods specifying the time at which each time period begins and finishes in the relevant Availability Declaration period in which such Aggregator is proposed to be available and at what wattage, expressed in a whole number of MW, and what limits for Ancillary Services, in respect of each such time period.

SDC1.2.3 Unit Scheduling and Dispatch Parameters

SDC1.2.3.1 By 1000 hours each day each Generator shall in respect of each CDGU that the Generator will have declared available under SDC1.2.2, submit to the Single Buyer in writing or by such electronic data transmission facilities as agreed upon with the Single Buyer any revisions to the Unit Scheduling and Dispatch Parameters to those submitted under a previous declaration to apply for the next following day or days from 0000 hours to 2400 hours for each day. The Unit Scheduling and Dispatch Parameters submitted by the Generator shall reasonably reflect the true operating characteristics.

SDC1.2.3.2 By 1000 hours each day each Generator shall in respect of each CDGU which the Generator shall have declared available under SDC1.2.2, submit to the Single Buyer in writing (or by such electronic data transmission facilities as have been agreed with the Single Buyer) the following:

(a) details of any special factors which in the reasonable opinion of the Generators may have a material effect or present an enhanced risk of a material effect on the likely output of such CDGUs. Such factors may include risks, or potential interruptions to CDGU fuel supplies, or developing plant problems. This information will normally only be used to assist in determining the appropriate level of Operating Reserve that is required under OC3.

(b) any temporary changes, and their possible duration, to the Registered Data of such CDGU;

(c) any temporary changes, and their possible duration, to the availability of Ancillary Services.

SDC1.2.3.3 By 1000 hours each day each Energy Storage Operator shall submit to the Single Buyer in writing (or by electronic data transmission facilities as agreed upon with the Single Buyer) any revisions to the Unit Scheduling and Dispatch Parameters to those submitted under a previous declaration to apply for the next following day or days from 0000 hours to 2400 hours for each day. The Unit Scheduling and Dispatch Parameters submitted by the Energy Storage Operator shall reasonably reflect the true operating characteristics.

SDC1.2.3.4 By 1000 hours each day each Aggregator shall submit to the Single Buyer in writing (or by electronic data transmission facilities as agreed upon with the Single Buyer) any revisions to the Unit Scheduling and Dispatch Parameters to those submitted under a previous declaration to apply for the next following day or days from 0000 hours to 2400 hours for each day.

SDC1.2.4 Least Cost Operation

SDC1.2.4.1 To meet the continuously changing demand on the Grid System in the most economical manner, CDGUs, Grid Connected Customers who can provide Demand Response in real time, must run units, Energy Storage Operators, Aggregators and Generators who have made production bid offers should be, as far as practicable, committed and dispatched in accordance with the least system operating cost with a satisfactory margin. For avoidance of doubt, generators participating in TPA are not subjected to this clause.

SDC1.2.4.2 A schedule that results in least cost will be compiled by the Single Buyer each day for the following day. When compiling the schedule, the Single Buyer will take account of and give due weight to the factors listed below (where applicable):

(a) CDGU Energy pricing information and methodologies as in the relevant Agreement;

(b) hydro/thermal optimisation;

(c) any operational restrictions or CDGU operational inflexibility;

(d) gas volume and pressure constraints, and other fuel constraints;

(e) minimum and maximum water-take for hydro CDGU and other factors associated with water usage or conservation;

(f) the export or import of Energy across the Interconnection;

(g) requirements by the State or Federal Government to conserve certain fuels;

(h) the Availability of a CDGU as declared in the Availability Notice;

(i) in cases where fuel prices are subsidized, the price to be used for scheduling shall be the price decided by the government;

(j) the Availability of an Energy Storage Unit as declared in the Availability Notice;

(k) minimum and maximum possible State Of Charge for Energy Storage Units;

(l) the Availability of an Aggregator as declared in the Availability Notice.

SDC1.2.4.3 In accordance with SDC1.2.4.1 and SDC1.2.4.2 above the Single Buyer shall prepare a Least Cost Unit Constrained Schedule.

SDC1.2.5 Constrained Schedule

SDC1.2.5.1 The Single Buyer will produce a Least Cost Unit Constrained Schedule, which will optimize overall operating costs and maintain a prudent level of Grid System security in accordance with the Transmission System Reliability Standards, and in accordance with Prudent Industry Practice.

SDC1.2.5.2 The Least Cost Unit Constrained Schedule shall take account of:

(a) Grid System requirements as determined by the GSO for voltage control and MVAr reserves;

(b) in respect of a CDGU the MW values registered in the current Unit Scheduling and Dispatch Parameters (SDP);

(c) the need to provide Spinning Reserve, as specified in OC3.1.2;

(d) CDGU stability, as determined by the GSO following advice from the Generator and registered in the SDP;

(e) the requirements for maintaining frequency control (in accordance with SDC3);

(f) the inability of any CDGU to meet its full Spinning Reserve capability or its Non-Spinning Reserve capability;

(g) the availability of Ancillary Services;

(h) Demand Response possible power variation from Grid Connected Customers and/or Network Operators and/or Distributors;

(i) Operation of a CDGU over periods of low Demand to provide sufficient margin in the view of the GSO to meet anticipated increases in Demand later in the current schedule day or the next following schedule day;

(j) Transfers to or from Interconnected Parties (as agreed and allocated by the GSO);

(k) Grid System constraints as System reliability requirements;

(l) Distribution Network constraints if applicable;

(m) testing and monitoring and/or investigations to be carried out under OC10 and/or commissioning and/or acceptance testing under the CC;

(n) System tests being carried out under OC11;

(o) any provisions by the GSO under OC7 for the possible islanding of the Grid System that requires additional Generating Modules to be Synchronized as a contingency action;

(p) any constraints for hydro generation;

(q) re-allocation of Spinning Reserve and Non-Spinning Reserve to take account of Grid System or Distribution Network constraints that affect the application of such reserve, and to take account of the possibility of islanding; and

(r) any other factors that may inhibit the application of the Least Cost Unit Constrained Schedule.

SDC1.2.5.3 The GSO shall carry out security assessment and shall advise the Single Buyer on any modification before the issuance of the Least Cost Unit Constrained Schedule. The Least Cost Unit Constrained Schedule will be deemed the Least Cost Unit Schedule for the following day.

SDC1.2.5.4 The Synchronizing and De-Synchronizing times shown in the Least Cost Unit Schedule are indicative only and it should be borne in mind that the Dispatch Instruction could reflect more or different CDGU than in the Least Cost Unit Schedule. The GSO may issue Dispatch Instruction in respect of any CDGU in accordance with its Declared Availability. Generators must ensure that their Generating Units are able to be synchronized at the times Scheduled but only if so Dispatched by the GSO by issue of a Dispatch Instruction;

SDC1.2.5.5 The Generation Unit Commitment will be issued to CDGUs by 1700 hours each day for the following day or days, providing that all necessary information was made available by 1000 hours. The GSO may instruct CDGUs before the issue of the Least Cost Unit Schedule for the Schedule Day that the instruction relates to, if the length of Notice to Synchronize requires the instruction to be given at the time. The Generation Unit Commitment received by each Generator will contain only information relating to its CDGUs.

SDC1.2.5.6 The Energy Storage Operator Unit Commitment will be issued to Energy Storage Operators by 1700 hours each day for the following day or days, providing that all necessary information was made available by 1000 hours. The Energy Storage Unit Commitment received by each Energy Storage Operator will only contain information relating to its Energy Storage Units.

SDC1.2.5.7 The Aggregators Commitment will be issued to Aggregators by 1700 hours each day for the following day or days, providing that all necessary information was made available by 1000 hours. The Aggregators Commitment received by each Aggregator will only contain information relating to its aggregated units.

SDC1.2.5.8 In the case of any change of Unit Scheduling and Dispatch Parameters from the relevant Agreement, these shall be notified to the Single Buyer and GSO;

SDC1.2.5.9 If a revision to an Availability Declaration, Unit Scheduling and Dispatch Parameters or Other Relevant Data is received by the Single Buyer prior to 1700 hours on the day prior to the relevant Schedule Day or Schedule Days, the Single Buyer shall, if there is sufficient time prior to the issue of the Least Cost Unit Schedule, take into account the revised Availability Declaration, Unit Scheduling and Dispatch Parameters or Other Relevant Data in preparing the Least Cost Unit Schedule.

SDC1.2.5.10 If a revision in Availability Declaration, Unit Scheduling and Dispatch Parameters or Other Relevant Data is received by the GSO before the Schedule Day, the GSO shall, if it reschedules the CDGUs, Energy Storage Units and Aggregators available, take into account the revised Availability Declaration, Unit Scheduling and Dispatch Parameters or Other Relevant Data in that rescheduling.

SDC1.3 Other Relevant Data

SDC1.3.1 Other Relevant Generator, Energy Storage Operator and Aggregator Data

SDC1.3.1.1 By 1000 hours each Scheduling Day each Generator shall for each CDGU that the Generator shall have declared available under SDC1.2.2, submit to the Single Buyer in writing (or by such electronic data transmission facilities as have been agreed with the Single Buyer) the following:

(a) details of any special factors which in the reasonable opinion of the Generator may have a material effect or present an enhanced risk of a material effect on the likely output of such CDGUs. Such factors may include risks or potential interruptions to CDGU fuel supplies or developing plant problems. This information will normally only be used to assist in determining the appropriate level of Operating Reserve that is required under OC3;

(b) any temporary changes, and their possible duration, to the Registered Data of such CDGU;

(c) any temporary changes, and their possible duration, to the availability of Ancillary Services;

(d) details of any CDGU's commissioning or recommissioning or changes in the commissioning or recommissioning programmes submitted earlier.

SDC1.3.1.2 By 1000 hours each Scheduling Day each Energy Storage Operator shall for each Energy Storage Unit that the Energy Storage Operator shall have declared available under SDC1.2.2, shall submit to the Single Buyer in writing (or by such electronic data transmission facilities as have been agreed with the Single Buyer) the following:

(a) details of any special factors which in the reasonable opinion of the Energy Storage Operator may have a material effect or present an enhanced risk of a material effect on the likely output of such Energy Storage Unit;

(b) any temporary changes, and their possible duration, to the Registered Data of such Energy Storage Unit;

(c) any temporary changes, and their possible duration, to the availability of Ancillary Services;

(d) details of any Energy Storage Unit's commissioning or recommissioning or changes in the commissioning or recommissioning programmes submitted earlier.

SDC1.3.1.3 By 1000 hours each Scheduling Day each Aggregator declared available under SDC1.2.2, shall submit to the Single Buyer in writing (or by such electronic data transmission facilities as have been agreed with the Single Buyer) the following:

(a) details of any special factors which in the reasonable opinion of the Aggregator may have a material effect or present an enhanced risk of a material effect on the likely output of such aggregated units;

(b) any temporary changes, and their possible duration, to the Registered Data of such Aggregator;

(c) any temporary changes, and their possible duration, to the availability of Ancillary Services.

SDC1.3.2 Distribution Network Data

SDC1.3.2.1 By 1000 hours each Scheduling Day each Distributor will submit to the Single Buyer in writing (or by such electronic data transmission facilities as have been agreed with the Single Buyer) confirmation or notification of the following in respect of the next following Availability Declaration Period or Periods:

(a) constraints on its Distribution Network which the Single Buyer may need to take into account;

(b) the requirements of voltage control and MVAr reserves which the GSO may need to take into account for Grid System security reasons; and

(c) the forecast of embedded production on its Distribution Network.

SDC1.3.3 Network Operator Data

SDC1.3.3.1 By 1000 hours each Scheduling Day each Network Operator will submit to the Single Buyer in writing (or by such electronic data transmission facilities as have been agreed with the Single Buyer) confirmation or notification of the following in respect of the next following Availability Declaration Period or Periods:

(a) constraints on its Network which the Single Buyer may need to take into account;

(b) the requirements of voltage control and MVAr reserves which the GSO may need to take into account for Grid System security reasons; and

(c) the forecast of embedded production on its Network.

SDC1.4 Data Validity Checking

The following data items together with any revisions to those data items, submitted by each Generator, Energy Storage Operator and Aggregator entered into computer systems of the Single Buyer producing the Least Cost Unit Schedule will be checked for validity with the Data Validity and Default Rules and will be automatically amended in accordance with those rules if the data items do not meet the requirements of those rules:

(a) the Availability Declaration (and other data listed under DRC8.1);

(b) the Unit Scheduling and Dispatch Parameters revisions; and

(c) the data listed under SDC1.3.1 (Other Relevant Data).

SDC1.4.1 If any CDGU, Energy Storage Operator or Aggregator fails to submit to the Single Buyer by 1000 hours each Scheduling Day any of the data and information required to be submitted pursuant to SDC1.2.2, SDC1.2.3, SDC1.2.4 for entry into the computer systems of the Single Buyer producing the Schedule, the data items to be used will be determined in accordance with the Data Validity and Default Rules. In any other case, the data items to be used will be the last valid data items submitted for the relevant Dispatch Unit.

SDC1.4.2 Any data which has been subjected to the Data Validity and Default Rules (whether or not amended or determined in accordance with those rules) which is inconsistent with other data will be amended in accordance with the Data Consistency Rules, if any.

SDC1.4.3 In the event that any data item of a CDGU is amended or determined in accordance with this SDC1.4, the appropriate data items will be made available to the Generator.

SDC1.4.4 It is the responsibility of the User to submit accurate data and also to notify the Single Buyer immediately of any changes to their data.

SDC1.5 Demand Response Data

SDC1.5.1 By 1000 hours each Scheduling Day Grid Connected Customers and Aggregators able to provide Demand Response will submit to the Single Buyer in writing (or by such electronic data transmission facilities as agreed upon with the Single Buyer) or notification of the following for the next following Availability Declaration Period:

(a) demand in discrete MW blocks that can be made available for control and the times when this control may be exercised;

(b) the notice required for each discrete MW block to be switched out and subsequently switched back in; and

(c) the price for each discrete MW block as specified in the relevant Agreement.

SDC1.5.2 It should be noted that Demand Response in this SDC1 is for the purpose of optimizing the total cost of Transmission Operation, and is not the same as Demand Control where there is insufficient generation, as described in OC4. It follows that, while the same Demand block may be offered for Demand Response and available for Demand Control it cannot be utilized for both purposes simultaneously and that the GSO may wish to retain for Demand Control any or all Demand blocks offered for Demand Response. Demand blocks utilized for

Demand Control under OC4 will not be paid the price specified in the relevant Agreement.

SDC1.5.3 A schedule of Demand Response received by each Grid Connected Customer or Aggregator will contain only information relating to that customer’s demand.

SDC1.6 External System Transfer Data

SDC1.6.1 Where an externally Interconnected Party outside Peninsular Malaysia is connected with the Grid System the power transaction will be governed by agreed interconnection operation manual and any other relevant Agreements. The GSO will be responsible for the Capacity Allocation of the interconnector based on the methodology defined in the relevant Agreement and approved by the Commission.

<End of the Scheduling and Dispatch Code No. 1: Unit Scheduling>

Scheduling and Dispatch Code No.2 (SDC2): Control, Scheduling and Dispatch

SDC2.1 Introduction, objectives and scope

SDC2.1.1 fThe provisions of sections MSDC2.1, MSDC2.2 and MSDC2.3 of the Main Code shall apply to this Scheduling and Dispatch Code No2: Control, Scheduling and Dispatch.

SDC2.2 Procedure

SDC2.2.1 Information Used

SDC2.2.1.1 The information that the GSO shall use for dispatching Generators, Energy Storage Operators and Aggregators will be:

(a) the Least Cost Unit Schedule;

(b) changes to any parameters used in the derivation of the Least Cost Unit Schedule following preparation of the Least Cost Unit Schedule;

(c) the provision of Ancillary Services taking into account changes to any parameters used in the derivation of the Least Cost Unit Schedule following preparation of the Least Cost Unit Schedule; and

(d) Planned transfer levels across Interconnections.

For avoidance of doubt, generators participating in TPA are must run unit. GSO shall have the right to instruct generators participating in TPA to reduce, maintain or increase the output subject to declared ATC by GSO or system condition.

SDC2.2.1.2 Subject as provided below, the factors used in the Dispatch phase in assessing which units to Dispatch, in conjunction with the Least Cost Unit Schedule as derived under SDC1, will be those used by the GSO to produce the Least Cost Unit Schedule as may be required depending on the reasonable opinion of the GSO in real time.

SDC2.2.1.3 Additional factors that the GSO will, however, also take into account are the actual performance in real time of Generators, Energy Storage Operators, Aggregators, Externally Interconnected Parties and Network Operators, agreed special actions (including Demand Control), actual network constraint in real time and variation between forecast and actual demand as these will have an effect on Dispatch.

SDC2.2.1.4 If two or more CDGUs, Energy Storage Unit, Aggregator have submitted identical data in accordance with SDC1, GSO will select first for Dispatch the one which in the GSO's reasonable judgement is most appropriate taking into account a possible reduction in transmission losses, higher system reliability and enhanced fuel security.

SDC2.3 Optimization of Least Cost Unit Schedule

SDC2.3.1 The GSO will revise the Least Cost Unit Schedule to be as optimal as possible when, in its reasonable judgement, a need arises. As it may be the case that no notice will be given prior to this optimization it is a requirement that Generators, Energy Storage Operators and Aggregators always inform the GSO of changes of Availability Declarations and Unit Scheduling and Dispatch Parameters immediately.

SDC2.4 Dispatch Instruction

SDC2.4.1 Issue and Variation

SDC2.4.1.1 Dispatch Instruction relating to the Schedule Day will normally be issued at any time during the period beginning immediately after the issue of the Least Cost Unit Schedule in respect of that Schedule Day.

Instruction, other than by electronic signals, which may be sent directly to the Generating Modules, Energy Storage Operators and Aggregators will always be sent to the User at the User's designated Control Room

SDC2.4.1.2 Dispatch Instruction will recognize the Declared Availability, Unit Scheduling and Dispatch Parameters and Other Relevant Data supplied to the GSO under SDC1 and any revisions under SDC1 or SDC2 to that data. A Dispatch Instruction may be subsequently cancelled or varied, including an instruction for a Cancelled Start.

SDC2.4.1.3 The GSO may issue Dispatch Instruction for any CDGU, Energy Storage Unit or Aggregator for which an Availability Declaration (or revised Availability Declaration) has been made in accordance with its Declared Availability as set out in the original or a revised, as the case may be, Availability Declaration, even if that CDGU, Energy Storage Unit or Aggregator was not included in the Least Cost Unit Schedule. The GSO is entitled to assume that each CDGU, Energy Storage Unit or Aggregator subject to the time dependent limitations on availability, is available to the extent declared in the latest Availability Declaration unless and until it is informed of any change.

SDC2.4.2 Scope of Dispatch Instruction for CDGUs

SDC2.4.2.1 In addition to instruction relating to Dispatch of Active Power, Dispatch Instruction may include:

(a) <u>Notice to Synchronize</u> - notice and changes in notice to Synchronize or De-Synchronize CDGUs in a specific timescale;

(b) <u>Active Power Output;</u>

(c) <u>Ancillary Services, </u>as defined in the related documents and the relevant Agreement<u>;</u>

(d) <u>Reactive Power</u> - to ensure that a satisfactory System voltage profile is maintained and that sufficient Reactive Power reserves are maintained, Dispatch Instruction may include, in relation to Reactive Power:

(i) <u>MVAr Output</u> - the individual MVAr output from the CDGU onto the Grid System on the higher voltage side of the generator step-up transformer.

(ii) Target Voltage Levels - target voltage levels, which may be controlled by AHVC, to be achieved by the CDGU on the Grid System on the higher voltage side of the generator step-up transformer or on selected adjacent buses. Where a CDGU is instructed to a specific target voltage, the CDGU must achieve that target within a tolerance of ±1 kV (or such other figure as may be agreed with the GSO) by tap changing on the generator or plant step-up transformer and/or adjusting AVR/reactive power compensation devices output setpoint, unless agreed otherwise with the GSO.

Under normal operating conditions, once this target voltage level has been achieved, the CDGU will not tap or adjust AVR/reactive power compensation devices output setpoint again without prior consultation with, and with the Agreement of the GSO.

However, under certain circumstances the CDGU may be instructed to maintain a target voltage until otherwise instructed and this will be achieved by tap changing on the generator or plant step-up transformer and/or adjusting AVR/reactive power compensation devices output without reference to the GSO.

(iii) Tap Changes - details of the required generator step-up transformer tap changes in relation to a CDGU. The instruction for tap changes may be a Simultaneous Tap Change instruction, whereby the tap change must be carried out by the Generator in response to an instruction from the GSO issued simultaneously to relevant Generators. The instruction, which is normally preceded by advance notice, must be carried out as soon as possible, and in any event within one (1) minute of receipt of the GSO’s instruction.

(iv) Maximum MVAr Output ("maximum excitation") - under certain conditions, such as low Grid System voltage, an instruction to maximum MVAr output as defined by the generator capability chart at instructed MW output ("maximum excitation") may be given, and a Generator should take appropriate actions to maximise MVAr output unless constrained by plant operational limits or safety grounds (relating to personnel or plant).

(v) Maximum MVAr Absorption ("minimum excitation") - under certain conditions, such as high System voltage, an instruction to maximum MVAr absorption as defined by the generator capability chart at instructed MW output ("minimum excitation") may be given, and a Generator should take appropriate actions to maximise MVAr absorption unless constrained by plant operational limits or safety grounds (relating to personnel or plant.

In addition:

(vi) the issue of Dispatch Instruction for Active Power at the Connection Point will be made with due regard to any resulting change in Reactive Power capability and may include instruction for reduction in Active Power generation to enable an increase in Reactive Power capability;

(vii) the excitation system, or equivalent control device in the case of Power Park Module, unless otherwise agreed with the GSO, must be operated only in its constant terminal voltage mode of operation with VAR limiters in service, with any constant Reactive Power output as control mode or constant Power Factor output control mode always disabled, unless agreed otherwise with the GSO. In the event of any change in System voltage, a Generator must not take any action to override the automatic MVAr response that is produced as a result of constant terminal voltage mode of operation of the automatic excitation control system unless instructed otherwise by the GSO or unless immediate action is necessary to comply with Stability Limits or unless constrained by plant operational limits or safety grounds (relating to personnel or plant);

(viii) a Dispatch Instruction relating to Reactive Power will be implemented without delay and will be achieved not later than two (2) minutes after the instruction time, or for longer period of time as the GSO may instruct.

(ix) in circumstances where the GSO issues new instruction in relation to more than one CDGU at the same Power Station at the same time, tapping will be carried out by the Generator, one tap at a time either alternately between (or in sequential order, if more than two), or at the same time on, each CDGU;

(x) where the instruction require more than two taps per CDGU and that means that the instruction cannot be achieved within two (2) minutes of the instruction time (or such longer period as the GSO may have instructed), the instruction must each be achieved with the minimum of delay after the expiry of that period;

(xi) on receiving a new MW Dispatch Instruction, no tap changing shall be carried out to change the MVAr output unless there is a new MVAr Dispatch Instruction;

(xii) where an instruction to Synchronize is given, or where a CDGU is Synchronized and a MW Dispatch Instruction is given, a MVAr Dispatch Instruction consistent with the CDGU's relevant parameters may be given. In the absence of a MVAr Dispatch Instruction with an instruction to Synchronize, the MVAr output should be 0 MVAr;

(xiii) where an instruction to De-Synchronize is given, a MVAr Dispatch Instruction, compatible with shutdown, may be given prior to De-Synchronization being achieved. In the absence of a separate MVAr Dispatch Instruction, it is implicit in the instruction to De-Synchronize that MVAr output should at the point of synchronism be 0 MVAr at De-Synchronization.

(xiv) it should be noted that should Grid System conditions require, the GSO may need to instruct maximum MVAr output to be achieved as soon as possible, but (subject to the provisions of paragraph (x) above) in any event no later than two (2) minutes after the instruction is issued;

(xv) upon receipt of a Dispatch Instruction relating to Reactive Power, the Generator may take what action as is necessary to maintain the integrity of the CDGU (including, without limitation, requesting a revised Dispatch Instruction), and must contact the GSO without delay;

(e) Frequency Sensitive Mode - reference to any requirement for change to or from Frequency Sensitive Mode for each CDGU as detailed in SDC3;

(f) Additional Generation - a requirement to provide any Additional Generation offered under the Scheduling process in SDC1;

(g) Future Dispatch Requirements - a reference to any implications for future Dispatch requirements and the security of the Grid System, including arrangements for change in output to meet post fault security requirements;

(h) Intertrips - an instruction to switch into or out of service an Operational Intertripping scheme;

(i) Special Protection Scheme - an instruction to switch into or out of service a Special Protection Scheme;

(j) Abnormal Conditions - instruction relating to abnormal conditions, such as adverse weather conditions, or high or low System voltage, operation under System islanding conditions as referred to in OC7 which may mean that the Least Cost Unit Schedule is departed from to a greater extent than usual. Revised operational data, replacing for example the current Unit Scheduling and Dispatch Parameters with revised parameters, may also apply pursuant to OC7;

(k) Tap Positions - a request for a CDGU step-up transformer tap position (for security assessment);

(l) Tests - an instruction to carry out tests as required under OC10;

(m) Synchronous condenser mode – operation of a synchronized hydro unit and providing no power into the Grid System, in accordance with CC6.4.17.1.

SDC2.4.2.2 Dispatch Instruction will indicate the target MW (at Target Frequency) to be provided at the Connection Point, and to be achieved in accordance with the respective CDGU's Unit Scheduling and Dispatch Parameters given under or as revised in accordance with SDC1 or SDC2, or such rate within those Parameters as is specified by the GSO in the Dispatch Instruction. The form of and terms to be used by the GSO in issuing instruction together with their meanings are set out in Appendix 1 in the form of a non-exhaustive list of examples.

SDC2.4.2.3 Dispatch Instruction will be given by telephone and will include an exchange of operator names or by automatic logging device or by electronic instruction.

SDC2.4.2.4 They must be formally acknowledged immediately by the Generator for the Power Station of that CDGU by telephone or automatic logging device or by such electronic data transmission facilities agreed upon with the GSO. With regards to non-acceptance of the instruction, there must be a reason given immediately, which may relate only to safety grounds (personnel or plant) or because they are not in accordance with the applicable Declared Availability, Unit Scheduling and Dispatch Parameters or Generation Other Relevant Data.

SDC2.4.2.5 Each Generator will comply with all Dispatch Instruction properly given by the GSO unless the Generator has given notice to the GSO regarding non-acceptance of Dispatch Instruction.

SDC2.4.2.6 In the event that in carrying out the Dispatch Instruction, an unforeseen problem arises, caused on safety grounds (relating to personnel or plant), the GSO must be notified without delay by telephone.

SDC2.4.2.7 Dispatch Instruction will be in accordance with Unit Scheduling and Dispatch Parameters and Generation Other Relevant Data registered under SDC1 or as amended under SDC1 or SDC2.

SDC2.4.2.8 Generators will respond to Dispatch Instruction properly given by the GSO with no more than the delay, as defined by the response times set out below provided that in the case of Emergency Instruction issued pursuant to SDC2.5 the obligation of the Generator shall be only to use all reasonable endeavors to so respond.

SDC2.4.2.9 Generators will only Synchronize or De-Synchronize CDGUs to the Dispatch Instruction of the GSO or unless that occurs automatically as a result of intertrip/interstart schemes or Low Frequency Relay operations. De-Synchronization may take place without prior agreement of the GSO if it is done purely on safety grounds (relating to personnel or plant). If that happens the GSO must be informed immediately that it has taken place.

SDC2.4.2.10 The GSO may suspend the issue of Dispatch Instruction in accordance with the Least Cost Unit Schedule to the extent that reports or data via the SCADA system that indicates a Partial Blackout or Total Blackout may be imminent or exists. When necessary the GSO will issue instruction for a Black Start.

SDC2.4.2.11 Each Generator in respect of any of its Power Station will without delay notify the GSO by telephone or by such electronic data transmission facilities agreed upon with the GSO of any change or loss (temporary or otherwise) to the operational capability including any changes to the Unit Scheduling and Dispatch Parameters or Generation Other Relevant Data supplied under SDC1 (and any revisions under SDC1 and SDC2 to the data) of each CDGU.

SDC2.4.2.12 If, for any reason, including a change of Declared Availability or Unit Scheduling and Dispatch Parameters made by the Generator or the submission of Generation Other Relevant Data, the prevailing Dispatch Instruction for any CDGU is no longer within the applicable Declared Availability, Unit Scheduling and Dispatch Parameters, or Generation Other Relevant Data then:

(a) the Generator will use reasonable endeavours to ensure that a revised Dispatch Instruction be given by the GSO such that the new Dispatch Instruction is within the now applicable Declared Availability and/or

Unit Scheduling and Dispatch Parameters and/or Generation Other Relevant Data; and

(b) if the GSO fails to issue such a new Dispatch Instruction within a reasonable time then the relevant Generator shall be entitled to change the operation of such CDGU to bring its operation within the applicable Declared Availability and/or Unit Scheduling and Dispatch Parameters and/or Generation Other Relevant Data until the GSO issues a new Dispatch Instruction within the applicable Declared Availability and/or Unit Scheduling and Dispatch Parameters and/or Generation Other Relevant Data. Prior to making such a change in operation, the Generator will use reasonable endeavours to advise the GSO by telephone and then confirmed by emails or by such electronic data transmission facilities agreed upon with the GSO of its intended action and its timing. The confirmation must be sent as soon as possible after the telephone call, but in the event that it is not possible to send it prior to the change of operation being carried out, the change may be effected prior to the notification. Any change in operation should be of the minimum necessary to remain within the applicable Declared Availability and/or Unit Scheduling and Dispatch Parameters and/or Generation Other Relevant Data.

SDC2.4.2.13 A Generator may request agreement of the GSO for one of the CDGUs to be operated under a risk of a trip. The agreement will be dependent on the risk to the Grid System that a trip of the CDGU would constitute.

SDC2.4.2.14 Each Generator will operate its Synchronized CDGUs with AVRs in constant terminal voltage mode with VAR limiters in service at all times. AVR constant Reactive Power or power factor mode should, if installed, be disabled, and its generator step-up transformer tap changer selected to manual mode unless released from this obligation in respect of a particular CDGU by the GSO. Where a power system stabilizer is fitted as part of an excitation system of a CDGU, it requires on-load commissioning which must be witnessed by the GSO. Only when the performance of the power system stabilizer has been approved by the GSO shall it be switched into service by a Generator and then it will be kept in service at all times unless otherwise agreed with the GSO.

SDC2.4.2.15 A Generator may request agreement from the GSO for one of its CDGUs to be operated with the AVR in manual mode, or power system stabilizer switched out, or VAR limiter switched out. The agreement of the GSO will be dependent on the risk that would be imposed on the Grid System and any User System.

SDC2.4.2.16 Dispatch Instruction may be given by telephone, or electronic message from the GSO or by such electronic data transmission facilities agreed upon with the GSO. Instruction will require formal acknowledgement from the Generator and will be recorded by the GSO in a written Dispatch log with the exception of the SCADA set point instruction. When appropriate electronic means are available, Dispatch Instruction shall be confirmed electronically. Generators shall also record all manual Dispatch Instruction in a written Dispatch log.

SDC2.4.2.17 Such dispatch logs and any other available forms of archived Instruction, for example, telephone recordings, shall be provided to the investigation team of the Commission when required. Otherwise, written records shall be kept by all parties for a period not less than five (5) years or as required by the relevant Agreement and voice recordings for a period not less than three (3) years.

SDC2.4.2.18 If, at any time, the GSO determines after consultations with the Generators that:

(a) continued synchronized operation of the generating facility may endanger the Grid System personnel;

(b) continued synchronized operation of the generating facility may endanger the Grid System integrity;

(c) continued synchronized operation of the generating facility may prevent maintenance of the Grid System's facilities; or

(d) the Generator's protective apparatus is not fully in service,

the GSO will have the right to disconnect the generation facility from the Grid System. The generating facility will remain disconnected until the GSO is satisfied that the condition(s) above has been corrected. The GSO shall also notify the Single Buyer, the Grid Owner or any relevant User of any of the conditions (a) through (d).

SDC2.4.3 Scope of Dispatch Instruction for Distributors, Network Operators and Grid Connected Customers who have agreed to Provide Demand Response

SDC2.4.3.1 Dispatch Instruction relating to the Schedule Day will normally be issued at any time during the period beginning immediately after the issue of the Least Cost Unit Schedule of that Schedule Day.

SDC2.4.3.2 Dispatch Instruction will recognize the Declared Availability declared, the discrete blocks made available for control and the notice required for each discrete MW block to be switched out and subsequently switched back in. A Dispatch Instruction may be subsequently cancelled or varied.

SDC2.4.3.3 The GSO will issue instruction directly to the Network Operator, Distributor, or Grid Connected Customer, as the case may be, for the Dispatch of each demand block available for control. The GSO is entitled to assume that each demand block available for control, subject to the time dependent limitations on availability, is available to the extent declared in the latest Availability Declaration unless and until it is informed of any change.

SDC2.4.3.4 Dispatch Instruction will include MW blocks to be controlled, times to be switched and whether the switching is for Demand Response as defined in SDC1.4 or Demand Control as defined in OC4. Grid Connected Customers shall respond to Dispatch Instruction without delay unless constrained by plant operational limits or safety grounds (relating to personnel or plant).

SDC2.4.3.5 Each Network Operator, Distributor, or Grid Connected Customer, as the case may be, will comply in accordance with all Dispatch Instruction properly given by the GSO unless the Grid Connected Customer has given notice which may only be on safety grounds (relating to personnel or plant) or because they are not in accordance with the applicable Declared Availability to the GSO regarding non-acceptance of Dispatch Instruction.

SDC2.4.3.6 In the event that in carrying out the Dispatch Instruction, an unforeseen problem arises, caused on safety grounds (relating to personnel or plant), the GSO must be notified without delay by telephone.

SDC2.4.4 Scope of Dispatch Instruction for Energy Storage Operators

SDC2.4.4.1 Dispatch Instruction to Energy Storage Operators may include:

(a) Charge or Discharge from the Energy Storage Unit to the Grid;

(b) Ancillary Service provision as defined in the related document and the relevant agreement.

SDC2.4.4.2 Each Energy Storage Operator will comply in accordance with all Dispatch Instruction properly given by the GSO unless the Energy Storage Operator has given notice which may only be on safety grounds (relating to personnel or plant) or because Dispatch Instruction are not in accordance with the applicable Declared Availability to the GSO regarding non-acceptance of Dispatch Instruction.

SDC2.4.4.3 In the event that when carrying out the Dispatch Instruction, an unforeseen problem arises, caused on safety grounds (relating to personnel or plant), the GSO must be notified by telephone without delay.

SDC2.4.5 Scope of Dispatch Instruction for Aggregators.

SDC2.4.5.1 Dispatch Instruction to Aggregators may include:

(a) Active power export or import blocks from the Aggregator’s aggregated units to the Grid;

(b) Ancillary Service provision as defined in the related document and the relevant Agreement

SDC2.4.5.2 Each Aggregator will comply in accordance with all Dispatch Instruction properly given by the GSO unless they are not in accordance with the applicable Declared Availability to the GSO regarding the non-acceptance of Dispatch Instruction.

SDC2.4.5.3 In the event that when carrying out the Dispatch Instruction, an unforeseen problem arises the GSO must be notified without delay by telephone.

SDC2.5 Reporting

SDC2.5.1 As part of the settlement process the GSO will publish data regarding the actual real time performance of each CDGU, Energy Storage Unit and Aggregator including TPA to the Single Buyer in a format agreed between the GSO and the Single Buyer;

SDC2.5.2 The GSO shall also provide requisite operational data in a format as specified by the Grid Code Committee/Grid Operation Subcommittee to enable them to perform their functions as per GC5.2 and GC7.1.

SDC2.6 Emergency Assistance Instruction

SDC2.6.1 To preserve Grid System integrity under emergency circumstances (as determined by the GSO in the reasonable opinion of the GSO) the GSO may issue Emergency Instruction to Generators, Energy Storage Operators and Aggregators. Such Emergency Instruction will be issued by the GSO direct to the User's Control Room for its Power Station or Energy Storage Unit or Aggregated Units and may require an action or response which is outside Unit Scheduling and Dispatch Parameters, Other Relevant Data or Notice to Synchronize registered under SDC1 or as amended under SDC1 or SDC2. Emergency Instruction may be given by telephone, or electronic message from the GSO or by such electronic data transmission facilities agreed upon with the GSO. This may, for example, be:

(a) an instruction to trip a Generating Module;

(b) an instruction to Part Load a Generating Module; or

(c) an instruction to operate Additional Generation

only requiring the User to use all reasonable endeavours to so respond, such Emergency Instruction must be complied with without delay. A refusal may only be given on safety grounds (relating to personnel or plant) and must be notified to the GSO immediately by telephone.

<End of the Scheduling and Dispatch Code No 2: Control, Scheduling and Dispatch>

Scheduling and Dispatch Code 2 - Appendix 1

SDC2A.1 Dispatch Instruction – Loading and Synchronizing

SDC2A.1.1 Form of Dispatch Instruction

SDC2A.1.1.1 All loading/de-loading rates will be assumed to be in accordance with Unit Scheduling and Dispatch Parameters. Each instruction will, wherever possible, be kept simple, drawing as necessary from the following forms.

SDC2A.1.1.2 The Dispatch Instruction will normally follow the form:

(a) an exchange of operator names;

(b) the specific CDGU to which the instruction applies;

(c) the output to which it is instructed;

(d) if the start time is different from the time the instruction is issued, the start time will be included;

(e) where specific loading/de-loading rates are concerned, a specific target time; and

(f) the issue time of the instruction.

SDC2A.1.2 Dispatching a Synchronized CDGU to increase or decrease output

SDC2A.1.2.1 If the time of the instruction is 1400 hours, the Unit is Unit 1 and the output to be achieved is 460MW, the relevant part of the instruction would be, for example: "Unit 1 to 460MW instruction timed at 1400”.

SDC2A.1.2.2 If the start time is 1415 hours, it would be, for example: "Unit 1 (or Module 1) to 460MW start at 1415 hours instruction timed at 1400”.

SDC2A.1.2.3 Loading and de-loading rates are assumed to be in accordance with Unit Scheduling and Dispatch Parameters unless otherwise stated. If different loading or de-loading rates are required, the time to be achieved will be stated, for example: "Unit 1 (or Module 1) to 460MW at 1420 hours target time instruction timed at 1400”.

SDC2A.1.3 CDGU Synchronizing

SDC2A.1.3.1 For CDGUs the instruction issue time will always have due regard for the time of Notice to synchronize declared to the GSO in the relevant Agreement the Generator.

SDC2A.1.3.2 The instruction will follow the form, for example: “Unit 1 synchronize at 1600 hours (and other units in sequence when scheduled) instruction timed at 1300 hours”.

SDC2A.1.3.3 Unless a loading programme is also given at the same time it will be assumed that the CDGUs are to be brought to Minimum Generation and (at the point of synchronism) 0 MVAr output, and on the Generator reporting that the Unit has Synchronized a further Dispatch Instruction will be issued.

SDC2A.1.3.4 When a Dispatch Instruction for a CDGU to Synchronize is cancelled before the Unit is Synchronized, the instruction will follow the form, for example: “Unit 1 (or Module 1), cancel Synchronizing instruction, instruction timed at 1400 hours”.

SDC2A.1.4 CDGU De-Synchronizing

SDC2A.1.4.1 The instruction will normally follow the form, for example: “Unit 1 Shutdown instruction timed at 1300 hours”.

SDC2A.1.4.2 If the instruction start time is for 1400 hours the form will be, for example: “Unit 1 Shutdown start at 1400 hours, instruction timed at 1300 hours (and other Units in sequence)”.

SDC2A.1.4.3 Both of the above assume a de-loading rate at declared Unit Scheduling and Dispatch Parameters. Otherwise the message will conclude with, for example: "... and De-Synchronize at 1500 hours”.

SDC2A.1.4.4 Unless a separate MVAr Dispatch Instruction is given, it will be assumed that the CDGU will be brought to 0 MVAr (at the point of synchronism) at De-Synchronization.

SDC2A.2 Dispatch Instruction – Loading and Synchronizing

SDC2A.2.1 Frequency Control

SDC2A.2.1.1 Grid System Frequency control is normally achieved by providing an AGC signal to each CDGU. All the above Dispatch will be deemed to be at the Target Frequency as transmitted by the AGC.

SDC2A.2.1.2 Where a CDGU cannot be instructed by an AGC signal, for whatever reason, and the CDGU is in the Frequency Sensitive Mode Instruction refer to target output at Target Frequency. In this instance Target Frequency changes will always be given to the Generator by facsimile or by such electronic data transmission facilities as have been agreed with the GSO and will normally only be 49.95, 50.00, or 50.05Hz but in exceptional circumstances as determined by the GSO in its reasonable opinion, may be 49.90 or 50.10Hz.

SDC2A.2.1.3 CDGUs required to operate in Frequency Sensitive Mode will be specifically instructed to operate so as to provide Primary Response and/or Secondary Response and/or High Frequency Response. The instruction will be of the form, for example: “Unit 1 (or Module 1) to 450 MW Primary and High Frequency Response instruction timed at 2100 hours”.

SDC2A.2.1.4 Frequency control instruction may be issued in conjunction with, or separate from, a Dispatch Instruction for ordinary Active Power output.

SDC2A.2.2 Voltage Control

SDC2A.2.2.1 In order for adequate System voltage profiles and Reactive Power reserves to be maintained under normal and fault conditions a range of voltage control instruction will be utilized from time to time, for example:

(a) Increase/decrease Reactive Power to 100 MVAr export or import;

(b) Maximum MVAr output (or "maximum excitation");

(c) Maximum MVAr absorption (or "minimum excitation");

(d) Increase CDGU step-up transformer tap position by [one] tap or go to tap position [x]; or

(e) For a Simultaneous Tap Change, change CDGU generator step-up transformer tap position by one [two] taps to raise or lower (as relevant) System voltage, to be executed at time of telegraph (or other) instruction;

(f) Achieve a target voltage of 280kV and then allow to vary with System conditions; or

(g) Maintain a target voltage of 280kV until otherwise instructed. Tap change as necessary.

SDC2A.2.2.2 In relation to MVAr Dispatch matters, MVAr generation/output is an export onto the System and is referred to as "lagging MVAr", and MVAr absorption is an import from the System and is referred to as "leading MVAr".

SDC2A.2.2.3 It should be noted that the excitation control system constant Reactive Power output control mode or constant power factor output control mode will always be disabled, unless agreed otherwise with the GSO.

SDC2A.3 Dispatch Instruction – Other Factors

SDC2A.3.1 Additional Generation/ Cancel Additional Gen

SDC2A.3.1.1 The instruction will be by facsimile instruction or if not available will be given by telephone or by such electronic data transmission facilities agreed upon with the GSO and will normally follow the form, for example: "Unit 1 instruct Additional Gen (or cancel Additional Gen), instruction timed at 1800 hours".

SDC2A.3.2 Black Start

SDC2A.3.2.1 The instruction will normally follow the form, for example: “Initiate Black Start procedure, instruction timed at 1900 hours”.

SDC2A.3.3 Emergency Instruction

SDC2A.3.3.1 The instruction will be prefixed with the words "This is an Emergency Instruction”. It may be in a pre-arranged format and will normally follow the form, for example: “This is an Emergency Instruction. Reduce output to ‘X’ MW in ‘Y’ minutes, instruction timed at 2000 hours”.

<End of the Scheduling and Dispatch Code No 2 – Appendix 1>

Scheduling and Dispatch Code No.3 (SDC3): Frequency and Interconnection Transfer Control

SDC3.1 Introduction, Objectives and Scope

SDC3.1.1 The provisions of sections MSDC3.1, MSDC3.2 and MSDC3.3 of the Main Code shall apply to this Scheduling and Dispatch Code No3: Frequency and Interconnection Transfer Control.

SDC3.2 Response from Power Station

SDC3.2.1 Each Generating Module, in accordance with its Ancillary Services requirements as defined in the Connection Code, the documents for Ancillary Services and the relevant agreement should at all times have the capability to operate automatically so as to provide response to changes in Frequency in order to contribute to containing and correcting the System Frequency within the statutory requirements of Frequency control.

SDC3.2.2 Each Generating Module producing Active Power, and able to do so, must operate at all times in a Frequency Sensitive Mode.

SDC3.2.3 The GSO may issue an instruction to a Generating Module to operate so as to provide Primary Response and/or Secondary Response and/or High Frequency Response. When so instructed, the Generating Module must operate in accordance with the instruction.

SDC3.2.4 Frequency Sensitive Mode is the generic description for a Generating Module operating in accordance with an instruction to operate so as to provide Primary Response and/or Secondary Response and/or High Frequency Response. Such instruction will continue until countermanded by the GSO or until the Generating Module is De-Synchronized, whichever is the first to occur.

SDC3.2.5 A System Frequency induced change in the Active Power output of a Generating Module which assists recovery to Target Frequency must not be countermanded by a Generating Unit or control system except where it is done purely on safety grounds (relating to either personnel or plant) or, where necessary, to ensure the integrity of the Generating Unit.

SDC3.3 Dispatch Instruction of the GSO in Relation to Demand Control and Demand Response

SDC3.3.1 The GSO may utilise Demand Control with the capability of Low Frequency Relay initiated load shedding in establishing its requirements for Frequency Control.

SDC3.3.2 The GSO will specify within the range agreed the Low Frequency Relay settings to be applied, the amount of Demand Control to be made available and will also instruct the Low Frequency Relay initiated response to be placed in or out of service.

SDC3.3.3 Users will comply with the Instruction of the GSO for Low Frequency Relay settings and Low Frequency Relay initiated Demand Control to be placed in or out of service. Users shall not alter such Low Frequency Relay settings or take Low Frequency Relay initiated response out of service without agreement of the GSO, except for safety reasons. If the User takes the Low Frequency initiated Demand Control facility out of service without the permission of the GSO that User must inform the GSO immediately.

SDC3.4 Response to High Frequency Required from Synchronized Plant

SDC3.4.1 Each Generating Unit in respect of which the Generator has been instructed to operate to provide High Frequency Response, producing Active Power and operating above Designed Minimum Operating Level, is required to reduce Active Power output in response to an increase in System Frequency above the Target Frequency.

SDC3.4.2 The rate of change of Active Power output with respect to Frequency up to 50.5 Hz shall be in accordance with the provisions from the relevant Agreement between the GSO and each Generator. The reduction in Active Power output by the amount provided for in the relevant Agreement between the GSO and the Generator must be fully achieved within ten (10) seconds of the time of the Frequency increase and must be sustained at no lesser reduction thereafter. It is accepted that the reduction in Active Power output may not be to below the Minimum Generation.

SDC3.4.3 In addition to the High Frequency Response provided, the Generating Unit must continue to reduce Active Power output in response to an increase in System Frequency to 50.5 Hz or above at a minimum rate of 2 per cent (%) of output per 0.1 Hz deviation of System Frequency above that level, such reduction to be achieved within five (5) minutes of the rise to or above 50.5 Hz.

SDC3.5 Plant Operating Below Minimum Generation

SDC3.5.1 Steady state operation below Minimum Generation is not expected but if System operating conditions cause operation below Minimum Generation which gives rise to operational difficulties for the Generating Unit, then the GSO should not, upon request, unreasonably withhold a Dispatch Instruction to return the Generating Unit to an output not less than Minimum Generation.

SDC3.5.2 It is possible that Synchronized Generating Modules which have responded as required under SDC3.4 to an excess of System Frequency, as therein described, will (if the output reduction is large or if the Generating Module output has reduced to below the Minimum Generation) trip after a time. All reasonable efforts should in the event be made by the Generator to avoid such tripping, provided that the System Frequency is below 52Hz.

SDC3.5.3 If the System Frequency is at or above 52Hz for a duration above the relay settings defined in CC6.4.9.2, the requirement to make all reasonable efforts to avoid tripping does not apply and the Generator is required to take action to protect the Power Station.

SDC3.5.4 In the event of the System Frequency becoming stable above 50.5Hz, after all Power Station action as specified in SDC3.4 has taken place, the GSO will issue appropriate Dispatch Instruction, which may include instruction to trip Generating Modules so that the Frequency returns to below 50.5Hz and ultimately to Target Frequency.

SDC3.5.5 If the System Frequency has become stable above 52 Hz, after all Power Station action as specified in SDC3.5.2 and SDC3.5.3 has taken place, the GSO will issue Dispatch Instruction to trip appropriate Generating Modules to bring the System Frequency to below 52Hz and follow this with appropriate Dispatch Instruction to return the System Frequency to below 50.5 Hz and ultimately to Target Frequency.

SDC3.6 General Issues

SDC3.6.1 The Generator will not be in default of any existing Dispatch Instruction if it is following the provisions of SDC3.2, SDC3.4 or SDC3.5.

SDC3.6.2 In order for the GSO to be able to deal with the emergency conditions effectively, it needs as much up to date information as possible. Accordingly the GSO must be informed of the action taken in accordance with SDC3.4 as soon as possible and in any event within five (5) minutes of the rise in System Frequency, directly by telephone from the Power Station.

SDC3.6.3 The GSO will use reasonable endeavors to ensure that, if System Frequency rises above 50.4Hz, and an Externally Interconnected Party is transferring Power into the Grid System, the amount of Power transferred into the Grid System from the System of that Externally Interconnected Party is reduced at a rate equivalent to (or greater than) that which applies for Generating Modules operating in Frequency Sensitive Mode which are producing Active Power. This will be done either by utilizing existing arrangements which are designed to achieve this, or by issuing Dispatch Instruction under SDC2.

SDC3.7 Frequency

SDC3.7.1 Frequency Control

SDC3.7.1.1 The GSO will endeavor (in so far as it is able) to control the system frequency within the statutory limits of 49.5Hz and 50.5Hz by specifying changes to Target Frequency and by Generation Dispatch.

SDC3.8 Interconnection Transfer Control - Externally Interconnected Party

SDC3.8.1 Any mutually agreed transfer of Power and/or Energy shall remain at the agreed transfer level when System Frequency is between 49.5Hz and 50.5Hz.

SDC3.8.2 If the frequency falls below 49.5Hz power transfers from the Grid System into an Externally Interconnected Party will be reduced to zero as soon as it is reasonably practical. In any case it must be accepted that at or below this frequency an Externally Interconnected Party may have disconnected the connection for preservation of its own system. The GSO must be aware of this possibility and plan Target Frequency and Generation Dispatch accordingly. The reduction of the transfer when the frequency is below 49.5 Hz, must be in accordance with the relevant TPA agreements.

<End of the Scheduling and Dispatch Code No 3: Frequency and Interconnection Transfer Control>

<End of the Scheduling and Dispatch Code >

Data Registration Code (DRC)

DRC.1 Preamble

DRC.1.1 The Grid Code is a code developed and issued by the Commission. The Grid Code is composed by a Main Code, containing the main provisions structuring the purpose, the scope, the governance and some general requirements, and by additional codes, containing the specific technical rules for different subjects related to the operation of the Grid system.

DRC.1.2 According to section 50A of the Electricity Supply Act 1990 [*Act 447*], the Commission may develop and issue such additional codes as it deems fit and expedient or the Minister may direct from time to time, as the case may be.

DRC.2 Amendment

DRC.2.1 The Commission may at any time amend, modify, vary or revoke this Code or any part thereof.

DRC.3 Introduction, Objectives and Scope

DRC.3.1 The provisions of sections MDRC1.1, MDRC1.2 and MDRC1.3 of the Main Code shall apply to this Data Registration Code.

DRC.4 Data categories and stages in Registration (Planning and Operational Data)

DRC.4.1 Within the DRC each data item is allocated to one of the following categories and stages for the Planning Data category:

(a) Planning Data:

(i) Preliminary Project Data (PPD);

(ii) Committed Project Data (CPD);

Contracted Project Data (TPD);

(b) Operational Data.

DRC.4.2 Preliminary Project Data is the Standard Planning Data provided by Users or intended Users to the Grid Owner based on which the Grid Owner will make an offer of physical connection.

DRC.4.3 Committed Project Data is the Standard Planning Data and Detailed Planning Data supplied by Users to the Grid Owner, GSO and Single Buyer, or the GSO and Grid Owner to Users, to enable System planning and operation to be carried out by the Grid Owner, GSO and Users.

DRC.4.4 Contracted Project Data is Standard Planning Data and Detailed Planning Data required by the Grid Owner, GSO and Single Buyer so that it can develop detailed models of the System and is expected to be an accurate description of User's Plant and Apparatus. This is entered into the project database as Registered Data or Estimated Registered Data.

DRC.4.5 Operational Data is data which is required by the Operating Codes and the Scheduling and Dispatch Codes and includes Demand forecast data.

DRC.4.6 Data listed in the schedules attached to this DRC within the category of Preliminary Project Data will also be required as Committed Project Data, Contracted Project Data and Registered Planning Data. Data listed in the schedules attached to this DRC within the category of Contracted Project Data will also be required as Registered Planning Data.

DRC.4.7 Standard Planning Data is the first to be provided by a User at the time of an application for a relevant Agreement. It comprises data which is expected normally to be sufficient for the Grid Owner and GSO to investigate the impact on the Grid System of any User Development associated with an application by the User.

DRC.4.8 Detailed Planning Data is usually the first set of data to be provided by the User within twenty-eight (28) days (or such longer period as the Grid Owner may agree in any particular case) of the offer for a physical connection, being accepted by the User. It comprises additional, more detailed, data. Users should note that, although not needed within twenty-eight (28) days of the offer, the term Detailed Planning Data also includes Operation Diagrams and Site Common Drawings produced in accordance with the Connection Code. The User may, however, be required by the GSO to provide the Detailed Planning Data in advance of the normal timescale before the Grid Owner can make an offer for physical connection.

DRC.4.9 In DRC, Year 0 means the current year at any time, Year 1 means the next year at any time, Year N+1 means the year after Year N. Each year will be considered to start on the 1st of January.

DRC.5 Connection Process and Information Exchange

DRC.5.1 In accordance with the provisions of the various sections of the Grid Code, each User must submit data as listed and collated in DRC7 and DRC8. Each User is responsible of validating the data before submittal.

DRC.5.2 The responsible parties for the data and the recipients of the data are stated in DRC7 and DRC8 for each DRC schedule. The responsible entity defines the standard format for data submission and the means of communication. The use of online platforms as a means of communication should be encouraged to allow secured access, automated processing, data validation mechanisms (data type, min/max values, etc) and proper traceability of data exchanges.

DRC.5.3 The recipients of the data should store the data in a referential database. The referential database should ensure confidentiality, integrity and availability.

DRC.5.4 Each data or list of data that is submitted should be stored in the referential database with at least the following information:

(a) The submission date;

(b) The submitter of the data;

(c) The validity of the data when relevant (not validated, validated, historized in case of replacement);

(d) The validator of the data;

(e) The Data Category for Planning data;

(f) The expiry date of the data when relevant and known.

DRC.6 Confidentiality of Data and Requirement to Provide Appropriate Data

DRC.6.1 Users, Grid Owner and the GSO are obliged to supply data as set out in the individual sections of the Grid Code and repeated in the DRC. If a User fails to supply data when required by any section of the Grid Code, the Grid Owner and GSO will estimate such data if and when, in the view of the Grid Owner and GSO, it is necessary to do so. If the Grid Owner and GSO fail to supply data when required by any section of the Grid Code, the User to whom that data ought to have been supplied will estimate such data if and when, in that User's view, 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 or Apparatus or upon such other information as the Grid Owner and GSO or that User deems appropriate.

DRC.6.2 The Grid Owner and GSO will advise a User in writing of any estimated data it intends to use relating directly to that User's Plant or Apparatus in the event of data not being supplied.

DRC.6.3 It is the responsibility of the recipient of any item of data to ensure that each item of data remains confidential and is not made available to any third party.

DRC.7 Schedules of Planning Data to be submitted

DRC.7.1 Planning Data Submission

DRC.7.1.1 Planning data submissions by Users shall be:

(a) with respect to each of the ten (10) succeeding years (other than in the case of Registered Data which will reflect the current position;

(b) provided by Users in connection with a relevant Agreement;

(c) provided by Users on a routine annual basis by January of each year to maintain an up-to-date data bank;

(d) where there is any change (or anticipated change) in Standard or Detailed Planning Data supplied to the Grid Owner under the PC, the User shall notify the Grid Owner in writing without delay. The notification of the change will be in the form required under the PC in relation to the supply of that data and will also contain the following information:

(i) the time and date at which the change became, or is expected to become, effective; and

(ii) if the change is only temporary, an estimate of the time and date at which the data will revert to the previous registered form.

DRC.7.2 DRC Planning Schedule 1 - Generating Module (other than Power Park Modules) Technical Data

DRC.7.2.1 The DRC Schedule comprises electrical parameters of Generating Modules to perform power flow and dynamics stability studies.

DRC.7.2.2 The Grid Owner is the responsible party for the data and GSO and the Grid Owner are the recipients of the data.

DRC.7.2.3 The Schedule is applicable to the following class of User:

(a) Generators other than Power Park Modules;

(b) Power Producers with Embedded Generating Plant other than Power Park Modules.

DRC.7.2.4 Data should be submitted annually in January or when applying for Connection.

DRC.7.2.5 Standard and Detailed Planning Data to be provided shall contain:

(a) Standard Planning Data for power flow study:

No.	Generator	Value	Unit	Remarks
1	Generator Unit Name		-	
2	Type of Unit (Steam Coal/Gas/Combine Cycle/Hydro/etc.)		-	
3	Terminal Voltage		kV	
4	Rated Apparent Power		MVA	
5	Rated Real Power		MW	
6	Lagging Power Factor at Rated Apparent Power		-	
7	Leading Power Factor at Rated Apparent Power		-	
8	Maximum Real Power, Pmax		MW	
9	Minimum Real Power, Pmin		MW	
10	Maximum Reactive Power, Qmax		MVAr	
11	Minimum Reactive Power, Qmin		MVAr	
12	Short Circuit Ratio		-	
13	Rated Field Current		A	
14	Rated Stator Current		A	
15	Rated Field Voltage		V	
16	Synchronous Machine Rotor Type		Salient/Solid/etc	
17	Number of Rotor Field Poles		-	
18	Nominal Mechanical Speed		RPM	
19	Efficiency		%	
20	Sub-transient Resistance, R Source		PU	
21	Sub-transient Reactance, X Source		PU	

No.	Generator	Value	Unit	Remarks
22	Generator Sequence Data			
	Positive Sequence Resistance, R1		PU	Per Unit Value shall base on Machine Rated Apparent Power(MVA)
	Positive Sequence Reactance, X1		PU	
	Negative Sequence Resistance, R2		PU	
	Negative Sequence Reactance, X2		PU	
	Zero Sequence Resistance, R0		PU	
	Zero Sequence Reactance, X0		PU	
23	Auxiliary Load		MW & MVAr	
24	Generator Data Sheet		Attachment	
25	Direct-axis Unsaturated			
	Synchronous Reactance (Xd)		PU	
	Transient Reactance (X'd)		PU	
	Sub-transient Reactance (X"d)		PU	
26	Open-circuit Time Constant (Direct-axis)			
	Transient Time Constant (T'do)		s	
	Sub-Transient Time Constant (T"do)		s	
27	Quadrature-axis Unsaturated			
	Synchronous Reactance (Xq)		PU	
	Transient Reactance (X'q)		PU	
	Sub-transient Reactance (X"q)		PU	
28	Open-circuit Time Constant (Quadrature-axis)			
	Transient Time Constant (T'do)		s	
	Sub-Transient Time Constant		s	

No.	Generator	Value	Unit	Remarks
	(T"do)			
29	Inertia Constant (for Whole Rotating Machine i.e. Turbines and Generator)		MW-sec/MVA	
30	Mass of Inertia (for Whole Rotating Machine i.e. Turbines and Generator)		Kgm^2	
31	Open Circuit Saturation Characteristic Curve - for Terminal Voltage Ranging from 0 p.u. to 1.2 p.u. of rated value in 10% steps as derived from appropriate manufacturers test certificates.		Curve	
32	To indicating corresponding field current values in Open Circuit Saturation Curve at terminal voltage: *(a)* 1.0 p.u. *(b)* 1.2 p.u.		PU	
33	Generator air-gap characteristic Curve indicating corresponding field current values at 1.0 p.u. and 1.2 p.u. of terminal voltage.		Curve	
34	To indicating corresponding field current values in Generator Air-Gap Characteristic Curve at terminal voltage of:		PU	
	(a) 1.0 p.u. *(b)* 1.2 p.u.			
35	Short Circuit Saturation Characteristic Curve		Curve	
36	To indicate corresponding field current values in Short Circuit		PU	

No.	Generator	Value	Unit	Remarks
	Saturation Curve at rated stator current.			
37	Reactive Power Capability Curve *(a)* to include at least the following: (i) Stator Current Limiter (ii) Maximum Excitation Limiter (iii) Minimum Excitation Limiter (iv) Locus of P/Q limiter		Curve	
38	Actual Commercial Date for Each Unit		Date/Month/Year	
39	Retirement Date for Each Unit		Date/Month/Year	
No.	Generator Power Transformer			
1	Primary, secondary & tertiary voltage		kV	
2	Transformer Rating, Rate A		MVA	
3	Sequence Impedance			
	Positive Sequence Resistance, R1		PU	
	Positive Sequence Reactance, X1		PU	
	Negative Sequence Resistance, R2		PU	
	Negative Sequence Reactance, X2		PU	
	Zero Sequence Resistance, R0		PU	
	Zero Sequence Reactance, X0		PU	
4	Winding MVA		MVA	
5	Upper limit on controlled voltage, Vmax		PU	
6	Lower limit on controlled voltage, Vmin		PU	
7	Maximum per-unit winding turns ratio, Rmax		PU	
8	Minimum per-unit winding turns ratio,		PU	

No.	Generator		Value	Unit	Remarks
	Rmin				
9	Vector Group			-	
10	Type of Tap Changer		On / Off Load	-	
	(a)	Number of Tap Positions		-	
	(b)	Step Size		PU	
	(c)	Impedance at maximum tap		PU	
	(d)	Impedance at minimum tap		PU	
	(e)	Sequence impedance at maximum tap		PU	
	(f)	Sequence impedance at minimum tap		PU	
11	Power transformer Data Sheet				
No.	Substation				
1	Detail layout drawing				
2	Busbar maximum continuous operating current			Amp	
3	Busbar maximum short circuit withstand current/time			Amp-sec	
4	Circuit breakers maximum short circuit withstand current/time			Amp-sec	
No.	Power Transformer				
1	Primary, secondary & tertiary voltage			kV	
2	Transformer Rating, Rate A			MVA	
3	Winding MVA			MVA	
4	Sequence Impedance				
		Positive Sequence Resistance, R1		PU	
		Positive Sequence Reactance,		PU	

No.	Generator		Value	Unit	Remarks
	X1				
	Negative Sequence Resistance, R2			PU	
	Negative Sequence Reactance, X2			PU	
	Zero Sequence Resistance, R0			PU	
	Zero Sequence Reactance, X0			PU	
5	Upper limit on controlled voltage, Vmax			PU	
6	Lower limit on controlled voltage, Vmin			PU	
7	Maximum per-unit winding turns ratio, Rmax			PU	
8	Minimum per-unit winding turns ratio, Rmin			PU	
9	Zero Sequence Resistance, R1			PU	
10	Zero Sequence Reactance, X1			PU	
11	Vector Group			-	
12	Type of Tap Changer		On / Off Load	-	
	(a)	Number of Tap Positions		-	
	(b)	Step Size		PU	
	(c)	Impedance at maximum tap		PU	
	(d)	Impedance at minimum tap		PU	
	(e)	Sequence impedance at maximum tap		PU	
	(f)	Sequence impedance at minimum tap		PU	
13	Power transformer Data Sheet				
No	Overhead Lines / Cable to the Adjacent Substations:				
1	Rated MVA			MVA	

No.	Generator	Value	Unit	Remarks
2	Rated Voltage		kV	
3	Operating Voltage		kV	
4	Length of circuit		km	
5	Number of Circuit		-	
6	3-Phase Positive Phase Sequence			
	Resistance, R1		PU	100MVA Base
	Reactance, X1		PU	
	Susceptance, B1		PU	
7	3-Phase Negative Phase Sequence			
	Resistance, R2		PU	100MVA Base
	Reactance, X2		PU	
	Susceptance, B2		PU	
8	3-Phase Zero Phase Sequence			
	Resistance, R0		PU	100MVA Base
	Reactance, X0		PU	
	Susceptance, B0		PU	
9	Lines / Cables Data Sheet			

(b) <u>Detailed Planning Data for dynamics stability study:</u>

No.	Generator	Remarks
1	Model Name	
2	Model Parameters	
3	Generator Capability Curve (.pdf & relevant software usable format)	
4	Block Diagram	
No.	Excitation System	
1	Model Name	

2	Model Parameters	
3	Block Diagram	
No.	Maximum Excitation Limiter	
1	Model Name	
2	Model Parameters	
3	Block Diagram	
No.	Minimum Excitation Limiter	
1	Model Name	
2	Model Parameters	
3.	Block Diagram	
No.	Power System Stabilizer	
1	Model Name	
2	Model Parameters	
3	Block Diagram	
No.	Turbine-Governor	
1	Model Name	
2	Model Parameters	
3	Block Diagram	

(c) Simulation model: Generator to provide steady state data, a dynamic standard model or user defined model (with source code) compatible with a software defined by the Grid Owner

No.	Steady State Data	Submission			
1	Power Flow Study Data	Yes	☐	No	☐
No.	Dynamic & Source Code Data	Submission			
1	Generator	Yes	☐	No	☐
2	Excitation	Yes	☐	No	☐

3	Maximum Excitation Limiter	Yes	☐	No	☐
4	Minimum Excitation Limiter	Yes	☐	No	☐
5	Power System Stabilizer	Yes	☐	No	☐
6	Turbine-Governor	Yes	☐	No	☐

DRC.7.3 DRC Planning Schedule 2 - Power Park Modules and Energy Storage Unit Technical Data

DRC.7.3.1 The DRC Schedule comprises electrical parameters of Power Park Modules and Energy Storage Unit to perform power flow and dynamics stability studies.

DRC.7.3.2 The Grid Owner is the responsible party for the data and GSO and the Grid Owner are the recipients of the data.

DRC.7.3.3 The Schedule is applicable to the following class of User:

(a) Generators with Power Park Modules;

(b) Power Producers with Embedded Power Park Modules;

(c) Energy Storage Operators.

DRC.7.3.4 Data should be submitted annually in January or when applying for Connection.

DRC.7.3.5 Standard and Detailed Planning Data to be provided shall contain:

(a) Standard Planning Data for power flow study:

No.	Inverter	Value	Unit	Remarks
1	Total Number of Inverter		-	
2	Base MVA (Single)		MVA	

3	Base MVA (Lumped)		MVA	
4	Maximum Real Power, Pmax (Lumped)		MW	
5	Minimum Real Power, Pmin (Lumped)		MW	
6	Maximum Reactive Power, Qmax (Lumped)		MVAr	
7	Minimum Reactive Power, Qmin (Lumped)		MVAr	
8	Equivalent Impedance (Lumped)		PU	
9	Inverter Data Sheet			
10	Commissioning Date		Date/Month/Year	
11	Retirement Date		Date/Month/Year	
No.	Energy Storage Unit			
1	Max active installed storage capacity		MW	
2	Max active Power unit at Point of Connection - Discharge		MW	
3	Max active Power unit at Point of Connection - Charge		MW	
4	Active and reactive auxiliary consumption (max, nom and min)		MW	
5	Max reactive power provided at Point of Connection when Energy Storage Unit stopped		MVAr	
6	Max Fault Infeed at Point of Connection		MVA	
7	Total Capacity - Energy		MWh	
8	Maximum State of Charge (SOCmax)		MWh	

9	Minimum State of Charge (SOCmin)		MWh	
10	Value above which Reserve Mode is activated to manage saturation of stock (SOCreserve sup)		MWh	
11	Value under which Reserve Mode is activated to manage stock exhaustion (SOCreserve min)		MWh	
12	Efficiency rate in Charge and Discharge		%	
13	Normal and exceptional operating range in voltage (MV), with duration, and corresponding protections		table	
14	Normal and exceptional operating range in frequency, with duration, and corresponding protections		table	
15	Max Apparent Power		MVA	
16	Nominal voltage		kV	
No.	Unit Transformer (Lumped)			
1	Primary, secondary & tertiary voltage		kV	
2	Positive Sequence Resistance, Specified R		PU	
3	Positive Sequence Reactance, Specified X		PU	
4	Transformer Rating, Rate A		MVA	
5	Winding MVA		MVA	
6	Upper limit on controlled voltage, Vmax		PU	
7	Lower limit on controlled voltage, Vmin		PU	

8	Maximum per-unit winding turns ratio, Rmax			PU	
9	Minimum per-unit winding turns ratio, Rmin			PU	
10	Zero Sequence Resistance, R1			PU	
11	Zero Sequence Reactance, X1			PU	
12	Vector Group			-	
13	Type of Tap Changer		On / Off Load	-	
	(a)	Number of Tap Positions		-	
	(b)	Step Size		PU	
	(c)	Impedance at maximum tap		PU	
	(d)	Impedance at minimum tap		PU	
	(e)	Sequence impedance at maximum tap		PU	
	(f)	Sequence impedance at minimum tap		PU	
14	Power transformer Data Sheet				
No.	Main Transformer (Lumped)				
1	Primary, secondary & tertiary voltage			kV	
2	Positive Sequence Resistance, Specified R			PU	
3	Positive Sequence Reactance, Specified X			PU	
4	Transformer Rating, Rate A			MVA	
5	Winding MVA			MVA	
6	Upper limit on controlled voltage, Vmax			PU	
7	Lower limit on controlled voltage, Vmin			PU	
8	Maximum per-unit winding turns			PU	

	ratio, Rmax			
9	Minimum per-unit winding turns ratio, Rmin		PU	
10	Zero Sequence Resistance, R1		PU	
11	Zero Sequence Reactance, X1		PU	
12	Vector Group		-	
13	Type of Tap Changer	On / Off Load	-	
	(a) Number of Tap Positions		-	
	(b) Step Size		PU	
	(c) Impedance at maximum tap		PU	
	(d) Impedance at minimum tap		PU	
	(e) Sequence impedance at maximum tap		PU	
	(f) Sequence impedance at minimum tap		PU	
14	Power transformer Data Sheet			
No.	Reticulation / Equivalent Network			
1	Impedances and Charging		PU	100MVA Base
2	Sequence Impedances and Charging		PU	100MVA Base
3	Layout Diagram			
No.	Substation			
1	Detail layout drawing			
2	Busbar maximum continuous operating current		Amp	
3	Busbar maximum short circuit withstand current/time		Amp/sec	
4	Circuit breakers maximum short		Amp/sec	

	circuit withstand current/time			
No.	Overhead Lines / Cable to the Adjacent Substations:			
1	Rated MVA		MVA	
2	Length		km	
3	Impedance & charging		PU	100MVA Base
4	Sequence impedance & charging		PU	100MVA Base
5	Lines / Cables Data Sheet			

(b) <u>Detailed Planning Data for dynamics stability study:</u>

No.	Solar Irradiance	Remarks
1	Model Name	
2	Model Parameters	
3	Block Diagram	
No	Solar Panel	
1	I-V Characteristic Curve	
2	Model Name	
3	Model Parameters	
4	Block Diagram	
No	Energy Storage Unit	
1	Detailed Diagram of Energy Storage Unit control-command	
2	Model parameters	
3	Block Diagram	
No.	Electrical Control Module	
1	Model Name	
2	Model Parameters	

3	Block Diagram	
No.	Power Converter / generator Module	
1	Reactive Power Capability Curve (for Single & Lumped Inverter) (.pdf & relevant software usable format)	
2	High Voltage / Low Voltage / Fault Ride Through Capability Curve	
3	Model Name	
4	Model Parameters	
5	Block Diagram	

(c) Simulation model: Generator and Energy Storage Operator to provide steady state data, dynamic standard model or user defined model (with source code) compatible with a software defined by the Grid Owner

No.	Steady State Data (in relevant software usable format)	Submission			
1	Power Flow Study Data	Yes	☐	No	☐
No.	*Dynamic & Source Code Data (in relevant software usable format)*	*Submission*			
1	Solar Irradiance	Yes	☐	No	☐
2	Solar Panel	Yes	☐	No	☐
3	Solar Panel	Yes	☐	No	☐
4	Energy Storage Unit	Yes	☐	No	☐
5	Power Converter / generator Module	Yes	☐	No	☐

DRC.7.4 DRC Planning Schedule 3 - Generation Availability, Scheduling and Dispatch Parameters for Planning

DRC.7.4.1 The DRC Schedule comprises the capabilities of a Generating Module in terms of Generation Availability, Scheduling and Dispatch Parameters. The data are used for planning studies.

DRC.7.4.2 Single Buyer is the responsible party for the data and the recipient of the data.

DRC.7.4.3 The Schedule is applicable to the following class of User:

(a) Generators;

(b) Power Producers with Embedded Power Park Modules.

DRC.7.4.4 Data should be submitted annually in January or when applying for Connection.

DRC.7.4.5 Data to be provided shall contain (on a module basis for Power Park Modules, unless otherwise stated):

DATA DESCRIPTION	UNITS	DATA CAT	VALUE
GENERATING UNIT AND POWER PARK MODULE:			
OUTPUT CAPABILITY			
Registered Capacity	MW	RGD	
Minimum Generation	MW	RGD	
MW available from Generating Units or Power Park Modules in excess of Registered Capacity	MW	RGD	
REGIME UNAVAILABILITY			

These data blocks are provided to allow fixed periods of unavailability to be registered			
Earliest Synchronizing time:			
Monday	hr/min	OC2	
Tuesday – Friday	hr/min	OC2	
Saturday – Sunday	hr/min	OC2	
Latest De-Synchronizing time:			
Monday – Thursday	hr/min	OC2	
Friday	hr/min	OC2	
Saturday – Sunday	hr/min	OC2	
SYNCHRONISING PARAMETERS			
Notice to Synchronise (NTS) after 48 hour Shutdown	Mins	OC2	
Station Synchronising Intervals (SI) after 48 hour Shutdown	Mins	OC2	
Synchronising Generation (SYG) after 48 hour Shutdown	MW	OC2	
De-Synchronising Intervals (Single value)	Mins	OC2	
RUNNING AND SHUTDOWN PERIOD LIMITATIONS:			
Minimum on time (MOT) after 48 hour Shutdown	Mins	OC2	
Minimum Shutdown time (MST)	Mins	OC2	
Two Shifting Limit (max. per day)	No.	OC2	

RUN-UP/RUN-DOWN PARAMETERS			
Run-up rate after 48 hour shutdown from synchronisation of Generating Unit or Power Park Module to Dispatched load level	MW/min	OC2	
Run-down rate from Generating Unit or Power Park Module Dispatched load level to Desynchronisation	MW/min	OC2	
REGULATION PARAMETERS			
Spinning Reserve Level	MW	OC2	
Loading rate from Spinning Reserve Level to Registered Capacity	MW/min	OC2	
Deloading rate from Registered Capacity to Spinning Reserve Level	MW/min	OC2	
Regulating Range	MW	OC2	
Load rejection capability while still Synchronised and able to supply Load.	MW	OC2	

DRC.7.5 DRC Planning Schedule 4 – Users System Data

DRC.7.5.1 The DRC Schedule comprises parameters related to the User System.

DRC.7.5.2 The Grid Owner is the responsible party for the data and GSO and the Grid Owner are the recipients of the data.

DRC.7.5.3 The data is required from Users who are connected to the Transmission System via a Grid Supply Point (or who are seeking such a connection).

DRC.7.5.4 Data should be submitted annually in January or when applying for Connection.

DRC.7.5.5 Standard and Detailed Planning Data to be submitted shall contain:

STANDARD PLANNING DATA DESCRIPTION	UNITS	DATA CATEGORY
USERS SYSTEM LAYOUT:		
A Single Line Diagram showing all or part of the User's System is required. This diagram shall include:-		CPD
(a) all parts of the User's System, whether existing or proposed, operating at 132kV, 275kV or 500kV,		
(b) all parts of the User's System operating at a voltage of 50kV or higher which can interconnect Connection Points, or split busbars at a single Connection Point		
(c) all parts of the User's System between Embedded Generating Plant or Energy Storage Unit Power Station connected to the User's Sub transmission System and the relevant Connection Point		
(d) all parts of the User's System at a site of the GSO.		
The Single Line Diagram may also include additional details of the User's Network System, and the transformers connecting the User's Network System to a lower voltage.		
This Single Line Diagram shall depict the arrangement(s) of all of the existing and proposed load current carrying Apparatus relating to both existing and proposed Connection Points, showing electrical circuitry (ie. overhead lines, underground cables, power transformers and similar equipment), operating voltages. In addition, for equipment operating at a Transmission Voltage, circuit breakers and phasing arrangements shall be shown.		

STANDARD PLANNING DATA DESCRIPTION	UNITS	DATA CATEGORY
For all parts of the User's Sub transmission System which are not included in the Single Line Diagram, each User shall provide the equivalent lumped shunt susceptance at nominal Frequency. This should include shunt reactors connected to cables which are not normally in or out of service independent of the cable.	MVar	
For all load current carrying Apparatus operating at 500kV and 275kV and 132kV, the Single Line Diagram shall include: *(a)* circuit breakers; and *(b)* phasing arrangements.		
REACTIVE COMPENSATION		
For independently switched reactive compensation equipment which is not owned by the GSO connected to the User's System at 132kV and above other than power factor correction equipment associated with a customer's Plant or Apparatus:		
Type of equipment (eg. fixed or variable)	Text	CPD
Capacitive rating; or	MVAr	CPD
Inductive rating; or	MVAr	CPD
Operating range	MVAr	CPD
Details of automatic control logic to enable operating characteristics to be determined	text and/or diagrams	CPD
Point of Connection to User's System (electrical location and system voltage)	Text	CPD
SUBSTATION INFRASTRUCTURE		

STANDARD PLANNING DATA DESCRIPTION	UNITS	DATA CATEGORY
For the infrastructure associated with any User's equipment at a Substation owned, operated or managed by the GSO:		
Rated 3-phase rms short-circuit withstand current	kA	CPD
Rated 1-phase rms short-circuit withstand current	kA	CPD
Rated Duration of short-circuit withstand	s	CPD
Rated rms continuous current	A	CPD

Circuit Parameters

The data below is all Standard Planning Data. Details are to be given for all circuits shown on the Single Line Diagram.

Years Valid	*Node 1*	*Node 2*	*Rated Voltage* *kV*	*Operating Voltage* *kV*	*Positive Phase Sequence* *% on 100 MVA*			*Zero Phase Sequence (self)* *% on 100 MVA*			*Zero Phase Sequence (mutual)* *% on 100 MVA*		
					R	*X*	*B*	*R*	*X*	*B*	*R*	*X*	*B*

<u>Notes</u>

1. Data should be supplied for the current, and each of the ten succeeding Years. This should be done by showing for which years the data is valid in the first column of the Table.

Transformer Data

The data below is all Standard Planning Data, and details should be shown below of all transformers shown on the Single Line Diagram. Details of Winding Arrangement, Tap Changer and earthing details are only required for transformers connecting the User's higher voltage system with its Primary Voltage System.

Years Valid	Name of Node or Connection Point	Trans-former	Rating MVA	Voltage Ratio		Positive Phase Sequence Reactance % on Rating			Positive Phase Sequence Reactance % on Rating			Zero Sequence Reactance % on Rating	Winding Arr.	Tap Changer			Earthing Details (delete as app.) *
				HV	LV	Max. Tap	Min. Tap	Nom. Tap	Max. Tap	Min. Tap	Nom. Tap			range +% to -%	step size %	type (delete as app.)	
																ON/ OFF	Direct/ Res/ Rea
																ON/ OFF	Direct/ Res/ Rea
																ON/ OFF	Direct/ Res/ Rea

*If Resistance or Reactance please give impedance value

<u>Notes</u>

1. Data should be supplied for the current Year, and for each of the ten succeeding Years. This should be done by specifying in the first column of the Table for which years the data is valid.

2. For a transformer with two secondary windings, the positive and zero phase sequence leakage impedances between the HV and LV1, HV and LV2, and LV1 and LV2 windings are required.

Switchgear Data

The data below is all Standard Planning Data for all switchgear (ie. circuit breakers, load disconnectors and disconnectors) operating at a Transmission Voltage. In addition, data should be provided for all circuit breakers irrespective of voltage located at a Connection Site which is owned by the Grid Owner, operated or managed by the GSO.

Years Valid	Connection Point	Switch No.	Rated Voltage kV rms	Operating Voltage kV rms	Rated short-circuit breaking current		Rated short-circuit peak making current		Rated rms continuous current (A)	DC time constant at testing of asymmetrical breaking ability(s)
					3 Phase kA rms	1 Phase kA rms	3 Phase kA peak	1 Phase kA peak		

Notes

1. Rated Voltage should be as defined by IEC 694.

2. Data should be supplied for the current Year, and for each of the ten succeeding Years. This should be done by specifying in the first column of the Table for which years the data is valid.

DETAILED PLANNING DATA DESCRIPTION	UNITS
PROTECTION SYSTEMS The following information relates only to Protection equipment which can trip or inter-trip or close any Connection Point circuit breaker or any circuit breaker of the Grid Owner and GSO. The information need only be supplied once and need not be supplied on a routine annual thereafter, although the GSO should be notified if any of the information changes. *(a)* A full description, including estimated settings, for all relays and Protection systems installed or to be installed on the User's System; *(b)* A full description of any auto-reclose facilities installed or to be installed on the User's System, including type and time delays; *(c)* A full description, including estimated settings, for all relays and Protection systems installed or to be installed on the Power Park Module or Generating Unit's generator transformer, unit transformer, station transformer and their associated connections; *(d)* For Generating Units (other than Power Park Units) having a circuit breaker at the generator terminal voltage clearance times for electrical faults within the Generating Unit zone must be declared;	
(e) Fault Clearance Times: Most probable fault clearance time for electrical faults on any part of the User's System directly connected to the Transmission Grid System.	mSec

Detailed Planning Data

Information for Transient Overvoltage Assessment

The information listed below may be requested by the Grid Owner or GSO from each User with respect to any Connection Site between that User and the Grid Owner or GSO. The impact of any third party Embedded within the User's System should be reflected as follows:

(a) Busbar layout plan(s), including dimensions and geometry showing positioning of any current and voltage transformers, through bushings, support insulators, disconnectors, circuit breakers, surge arresters, etc. Electrical parameters of any associated current and voltage transformers, stray capacitances of wall bushings and support insulators, and grading capacitances of circuit breakers;

(b) Electrical parameters and physical construction details of lines and cables connected at that busbar. Electrical parameters of all plant e.g., transformers (including neutral earthing impedance or zig-zag transformers if any), series reactors and shunt compensation equipment connected at that busbar (or to the tertiary of a transformer) or by lines or cables to that busbar;

(c) Basic insulation levels (BIL) of all Apparatus connected directly, by lines or by cables to the busbar;

(d) Characteristics of overvoltage Protection devices at the busbar and at the termination points of all lines, and all cables connected to the busbar;

(e) Fault levels at the lower voltage terminals of each transformer connected directly or indirectly to the Transmission Grid System without intermediate transformation;

(f) The following data is required on all transformers operating at Transmission Voltage: three or five limb cores or single-phase units to be specified, and operating peak flux density at nominal voltage;

(g) An indication of which items of equipment may be simultaneously out of service during Planned Outage conditions.

Harmonic Studies

The information given below, both current and forecast, where not already supplied in this Schedule 5 may be requested by the Grid Owner from each User if it is necessary for the Grid Owner or GSO to evaluate the production/magnification of harmonic distortion on systems of

Users and the Grid Owner or GSO. The impact of any third party Embedded within the User's System should be reflected as follows:

(a) Overhead lines and underground cable circuits of the User's Sub transmission System must be differentiated and the following data provided separately for each type:

(i) Positive phase sequence resistance;

(ii) Positive phase sequence reactance;

(iii) Positive phase sequence susceptance.

(b) For all transformers connecting the User's Sub transmission System to a lower voltage:

(i) Rated MVA;

(ii) Voltage Ratio;

(iii) Positive phase sequence resistance;

(iv) Positive phase sequence reactance.

(c) At the lower voltage points of those connecting transformers:

(i) Equivalent positive phase sequence susceptance;

(ii) Connection voltage and MVAr rating of any capacitor bank and component design parameters if configured as a filter.

(iii) Equivalent positive phase sequence interconnection impedance with other lower voltage points

(iv) The Minimum and maximum Demand (both MW and MVAr) that could occur.

(v) Harmonic current injection sources in Amps at the Connection voltage points.

(vi) Details of traction loads, eg connection phase pairs, continuous variation with time, etc.

(d) An indication of which items of equipment may be out of service simultaneously during Planned Outage conditions.

Voltage Assessment Studies

The information listed below, where not already supplied in this Schedule 5, may be requested by the Grid Owner or GSO from each User with respect to any Connection Site if it is necessary for the Grid Owner or GSO to undertake detailed voltage assessment studies (eg to examine potential voltage instability, voltage control co-ordination or to calculate voltage step changes). The impact of any third party Embedded within the Users System should be reflected as follows:

(a) For all circuits of the User’s Sub transmission System—

(i) Positive Phase Sequence Reactance;

(ii) Positive Phase Sequence Resistance;

(iii) Positive Phase Sequence Susceptance;

(iv) MVAr rating of any reactive compensation equipment.

(b) For all transformers connecting the User's Sub transmission System to a lower voltage—

(i) Rated MVA;

(ii) Voltage Ratio;

(iii) Positive phase sequence resistance;

(iv) Positive Phase sequence reactance;

(v) Tap-changer range;

(vi) Number of tap steps;

(vii) Tap-changer type: on-load or off-circuit;

(viii) AVC/tap-changer time delay to first tap movement;

(ix) AVC/tap-changer inter-tap time delay;

(c) At the lower voltage points of those connecting transformers—

(i) Equivalent positive phase sequence susceptance;

(ii) MVAr rating of any reactive compensation equipment;

(iii) Equivalent positive phase sequence interconnection impedance with other lower voltage points;

(iv) The maximum Demand (both MW and MVAr) that could occur;

(v) Estimate of voltage insensitive (constant power) load content in % of total load at both winter peak and 75% off-peak load conditions.

Short Circuit Analyses

The information listed below, both current and forecast, and where not already supplied under this Schedule 5, may be requested by the Grid Owner or GSO from each User with respect to any Connection Site where prospective short-circuit currents on equipment owned, operated or managed by the Grid Owner or GSO are close to the equipment rating. The impact of any third party Embedded within the User's System should be reflected:

(a) For all circuits of the User's Sub transmission System:

(i) Positive phase sequence resistance;

(ii) Positive phase sequence reactance;

(iii) Positive phase sequence susceptance;

(iv) Zero phase sequence resistance (both self and mutuals);

(v) Zero phase sequence reactance (both self and mutuals);

(vi) Zero phase sequence susceptance (both self and mutuals).

(b) For all transformers connecting the User's Sub transmission System to a lower voltage:

(i) Rated MVA;

(ii) Voltage Ratio;

(iii) Positive phase sequence resistance (at max, min and nominal tap);

(iv) Positive Phase sequence reactance (at max, min and nominal tap);

(v) Zero phase sequence reactance (at nominal tap);

(vi) Tap changer range;

(vii) Earthing method: direct, resistance or reactance;

(viii) Impedance if not directly earthed.

(c) At the lower voltage points of those connecting transformers:

(i) The maximum Demand (in MW and MVAr) that could occur—

(ii) Short-circuit infeed data in accordance with PC.A.2.5.4(a) unless the User's lower voltage network runs in parallel with the Sub transmission System, when to prevent double counting in each node infeed data, a p equivalent comprising the data items of PC.A.2.5.4(a) for each node together with the positive phase sequence interconnection impedance between the nodes shall be submitted.

HVDC and Power Electronic Devices

It is occasionally necessary for the Grid Owner and GSO to undertake studies involving HVDC and Power Electronic Devices (e.g. SVC, FACTS etc). At the Grid Owner and GSO's reasonable request, each User is required to provide the following data, as follows:

(a) HVDC configuration including rating of converter (MW, voltage and current), converter transformer, DC Smoothing Reactors, and DC Filters;

(b) AC Filters, shunt capacitors, and reactors;

(c) Detailed block diagrams For HVDC Control System in a form that is compatible with the software specified by Grid Owner and GSO;

(d) Master Power Controls;

(e) Pole Controls (current control, voltage control, extinction angle control);

(f) VDCL (Voltage Dependent Current Limits);

(g) Firing Controls (Phase Locked Loop);

(h) Reactive power controller (Q or V Control);

(i) Supplementary stability control function such fast ramp up/down, frequency limit control and power oscillation damping;

(j) SVC configuration including rating of converter (MVar, voltage and current);

(k) Detailed block diagrams For Static Var Compensator (SVC) or STATCOM Control System in a form that is compatible with the software specified by Grid Owner and GSO;

(l) MVAr Control;

(m) Voltage Control;

(n) Power Oscillation Damping Control;

(o) Susceptance Control;

(p) Adaptive Gain Control.

DRC.7.6 DRC Planning Schedule 5 – Demand and Active Energy Data

DRC.7.6.1 The DRC Schedule comprises Forecast Data about the demand and Active Energy of a User.

DRC.7.6.2 The Single Buyer is the responsible party for the data and the recipient of the data.

DRC.7.6.3 The Schedule is applicable to the following class of User:

(a) Network Operator on its User System;

(b) Distributor on its User System;

(c) Grid Connected User.

DRC.7.6.4 Data should be submitted annually in January or when applying for Connection.

Standard Planning Data shall be submitted by the end of January of each year and shall contain:

DATA DESCRIPTION	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	DATA CAT
SPECIFIC HALF HOUR DEMANDS AND POWER FACTORS (see Notes 2, 3, 5, 7 and 8)												
Individual Connection Point Demands and Power Factor at: (name of GSP)												
The annual peak half-hour at the Connection Point (MW/p.f.)												CPD
Lumped Susceptance (See Note 6)												CPD
Deduction made for Independent and Customer Power Station (MW)												CPD
The annual peak half hour of Power System Demand (MW/p.f.) at the specified time (See Note 9)												CPD
Deduction made for Independent and Customer Power Station (MW)												CPD
The annual minimum half-hour at the Connection Point (MW/p.f.)												CPD

DATA DESCRIPTION	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	DATA CAT
The annual minimum half hour of the Power System Demand (MW/p.f.), average conditions, at the specified time (See Note 9)												CPD
Deduction made for Embedded Power Station (MW)												CPD
For such other times as the Single Buyer , Grid Owner and GSO may specify (MW/p.f.)												CPD
Deduction made for Embedded Power Station (MW)												CPD
ANNUAL ACTIVE ENERGY REQUIREMENT (average conditions)												
Domestic (MWh)												
Commercial (MWh)												
Industrial (MWh)												
Public Lighting (MWh)												
Mining (MWh)												
Other (MWh)												
User System Losses (MWh)												

DATA DESCRIPTION	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	DATA CAT
DEMAND TRANSFER CAPABILITY (PRIMARY SYSTEM)												
Where a User's Demand, may be fed from alternative Connection Point(s) the following information should be provided												
First circuit outage (fault outage) conditions												
Name of the alternative Connection Point(s)												CPD
Demand transferred (MW)												CPD
Demand transferred (MVAr)												CPD
Transfer arrangement, i.e Manual (M) Interconnection (I) Automatic (A)												CPD
Time to effect transfer (hrs)												CPD
Second Circuit outage (planned outage) condition												
Name of the alternative												CPD

DATA DESCRIPTION	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	DATA CAT
Connection Point(s)												
Demand transferred (MW)												CPD
Demand transferred (MVAr)												CPD
Transfer arrangement, i.e Manual (M) Interconnection (I) Automatic (A)												CPD
Time to effect transfer (hrs)												CPD
<u>INDEPENDENT AND CUSTOMER GENERATION SUMMARY</u>												
For each Connection Point where there are Embedded Power Stations the following information is required:												
No. of Embedded Power Stations												CPD
Number of Generating Units within these stations												CPD
Summated Capacity of all these Generating Units												CPD

DATA DESCRIPTION	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	DATA CAT
Where the Network Operator's System places a constraint on the capacity of an Embedded Centrally Dispatched Generating Unit:												
Station Name												CPD
Generating Unit												CPD
System Constrained Capacity												CPD

NOTES

1. 'Yr' means Year. Yr 0 refers to the current Year.

2. Demand Data (General)

All Demand data should be net of the output (as reasonably considered appropriate by the User) of all Embedded Power Station. Auxiliary demand of Embedded Power Stations should not be included in the demand data submitted by the User. Users should refer to the PC for a complete definition of the Demand to be included. The data to be supplied by each Distributor or Network Operator will include, if any exists, Demand being (or to be) met by other Distributors or Network Operators supplying Customers in the User System together with Active Energy requirements relating thereto. Accordingly, if a Distributor or Network Operator receives forecast data from another Distributor or Network Operator and intends to use that data in preparing data to be supplied to the Grid Owner, Single Buyer and GSO, each Distributor or Network Operator must ensure that the Demand and Active Energy requirements forecasts provided by those Distributors or Network Operators are prepared in accordance with Prudent Industry Practice.

3. Peak Demands should relate to each Connection Point individually and should provide the maximum demand that in the User's opinion could reasonably be imposed on the Grid System. Where the busbars on a Connection Point are expected to be run in separate sections separate Demand data should be supplied for each such section of busbar.

   In deriving Demands any deduction made by the User (as detailed in note 2 above) to allow for Embedded Power Station is to be specifically stated as indicated on the Schedule.

4. The GSO may at its discretion require details of any Embedded Power Station whose output can be expected to vary in a random manner (e.g. wind power) or according to some other pattern (e.g. tidal power).

5. Where more than 95% of the total Demand at a Connection Point is taken by synchronous motors, values of the Power Factor at maximum and minimum continuous excitation may be given instead.

6. Power Factor data should allow for series reactive losses on the User's System but should exclude reactive compensation specified separately, and any network susceptance should be provided separately.

7. Data being supplied on a half hourly basis refer to it being supplied for each period of thirty (30) minutes ending on the hour or half-hour in each hour.

8. In assembling its Demand and Active Energy requirements forecast, each Distributor or Network Operator must endeavour to avoid duplication between the Demand together with Active Energy requirements relating thereto being and to be met by each of the Distributors or Network Operators supplying Customers in the User System. Therefore, in formulating its Demand and Active Energy requirements forecast, each Distributor or Network Operator will only include in the Demand it expects to be met together with Active Energy requirements relating thereto:

(a) that Demand together with Active Energy requirements relating thereto in respect of which there is a contractual arrangement to meet (whether or not that Demand and those Active Energy requirements exist at the date of the forecast);

(b) any anticipated development in Demand and Active Energy requirements relating to that contractual arrangement

(c) any anticipated development in Demand and Active Energy requirements relating to Customers generally (whether or not a contractual arrangement then exists); and

(d) where a contractual arrangement exists, or where a person is anticipated to be a Customer, for only a portion of the period for which data is required, will include an assumption for the remainder of that period (which will be identified as an assumption in the data submission) unless it is aware that that Demand will be met by other Users acting as Suppliers, which will be reflected in any event in its Demand and Active energy requirements forecast.

The Demand and Active Energy requirements forecast may include specific reservations on particular aspects of the forecast.

9. No later than by the end of January each year the Single Buyer shall notify each Distributor or Network Operator and Grid Connected Customer in writing of the following, for the current year and for each of the following ten (10) year, which will, until replaced by the following year's notification, be regarded as the relevant specified days and times:

(a) the date and time of the annual peak Demand; and

(b) the date and time of the annual minimum Demand.

DRC.7.7 DRC Planning Schedule 6 – Load Characteristics

DRC.7.7.1 The DRC Schedule comprises information about the demand of a User.

DRC.7.7.2 GSO is the responsible party for the data and the recipient of the data.

DRC.7.7.3 The Schedule is applicable to the following class of User:

(a) Customers.

DRC.7.7.4 Data shall be submitted when requested by GSO.

DRC.7.7.5 Standard Planning Data shall be provided by connection point and shall contain:

DATA DESCRIPTION	**UNITS**	**DATA FOR FUTURE YEARS**				
		Yr 1	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**
FOR ALL TYPES OF DEMAND FOR EACH GRID SUPPLY POINT						
The following information is required infrequently and should only be supplied, wherever possible, when requested by the Grid Owner and GSO:						
Details of individual loads which have significantly different Characteristics from the typical range of domestic or commercial and industrial load supplied		Please attach				
Sensitivity of demand to fluctuations in voltage and frequency on Transmission System at time of peak						

DATA DESCRIPTION	UNITS	DATA FOR FUTURE YEARS				
		Yr 1	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**
Connection Point Demand (Active and Reactive Power)*:						
(a) Voltage Sensitivity	MW/kV MVAr/kV					
(b) Frequency Sensitivity	MW/Hz MVAr/HZ					
Reactive Power sensitivity should relate to the Power Factor information given in Schedule 11 r (or for Generating Units, Schedule 1)						
Phase unbalance imposed on the Transmission System						
(a) maximum	%					
(b) average	%					
Maximum Harmonic Content imposed on the Transmission System	%					
Details of any loads which may cause Demand Fluctuations greater than 1 MVA:						
(a) cyclic variation of Active Demand	MW					
(b) cyclic variation of Reactive Demand	MVAR					

DATA DESCRIPTION	UNITS	DATA FOR FUTURE YEARS				
		Yr 1	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**
(c) rate of change of increasing Active Demand	MW					
(d) rate of change of increasing Reactive Demand	MVAR					
(e) rate of change of decreasing Active Demand	MW					
(f) rate of change of decreasing Rective Demand	MVAR					
(g) shortest repetitive time interval between fluctuations in Active Demand	s					
(h) shortest repetitive time interval between fluctuations in Reactive Demand	s					
(i) magnitude of largest step changes in increasing Active Demand	MW					
(j) magnitude of largest step changes in increasing Reactive Demand	MVAR					
(k) magnitude of largest step changes in decreasing Active Demand	MW					
(l) magnitude of largest step changes in decreasing Reactive Demand	MVAR					

DATA DESCRIPTION		UNITS	DATA FOR FUTURE YEARS				
			Yr 1	Yr 2	Yr 3	Yr 4	Yr 5
(m)	(v) maximum Energy demanded per hour by the fluctuating Demand cycle	MWh					
(n)	steady state residual Active Demand occurring between Demand fluctuations	MW					
(o)	steady state residual Reactive Demand occurring between Demand fluctuations	MVAR					

*The sensitivity factors quoted for the Demand (Reactive Power) should include any User's System series reactive losses but exclude any independently switched reactive compensation.

DRC.7.8 DRC Planning Schedule 7 – Fault Infeed Data from Users (other than Generators)

DRC.7.8.1 The DRC Schedule comprises information about the Fault Infeed of Users (other than a Generator) who are connected to the Transmission System via a Connection Point (or who are seeking such a connection), in order to enable the Grid Owner and GSO to calculate fault currents. A separate submission is required for each node included in the Single Line Diagram at which motor loads and/or Embedded Generating Unit(s) are connected, assuming a fault at that location.

DRC.7.8.2 Grid Owner is the responsible party for the data and Grid Owner and GSO are the recipients of the data.

DRC.7.8.3 The Schedule is applicable to the following class of User:

(a) Distributors;

(b) Grid Connected Customers;

(c) Network Operators;

(d) Energy Storage Operators.

DRC.7.8.4 The Data shall be submitted annually be the end of January or when applying for Connection.

DRC.7.8.5 Standard Planning Data to be provided shall contain:

DATA DESCRIPTION	UNITS	VALUE
<u>SHORT CIRCUIT INFEED TO TRANSMISSION SYSTEM FROM USERS SYSTEM AT A CONNECTION POINT</u>		
Name of node or Connection Point		
Symmetrical three phase short-circuit current infeed		
- at instant of fault	kA	
- after sub transient fault current contribution has substantially decayed	kA	
Zero sequence source impedances as seen from the Point of Connection or node on the Single Line Diagram (as appropriate) consistent with the maximum infeed above:		
(a) Resistance	% on 100 MVA	
(b) Reactance	% on 100 MVA	
Positive sequence X/R ratio at instance of fault		

DATA DESCRIPTION	UNITS	VALUE
Pre-Fault voltage magnitude at which the maximum fault currents were calculated	p.u.	
Negative sequence impedances of User's System as seen from the Point of Connection or node on the Single Line Diagram (as appropriate). If no data is given, it will be assumed that they are equal to the positive sequence values.		
(a) Resistance	% on 100 MVA	
(b) Reactance	% on 100 MVA	

DRC.7.9 DRC Planning Schedule 8 – Fault Infeed Data from Generators

DRC.7.9.1 The DRC Schedule comprises information about the Fault Infeed of Generators who are connected to the Transmission System via a Connection Point (or who are seeking such a connection), in order to enable the Grid Owner and GSO to calculate fault currents. A separate submission is required for each node included in the Single Line Diagram at which motor loads and/or Embedded Generating Unit(s) are connected, assuming a fault at that location.

DRC.7.9.2 Grid Owner is the responsible party for the data and Grid Owner and GSO are the recipients of the data.

DRC.7.9.3 The Schedule is applicable to the Generators.

DRC.7.9.4 The Data shall be submitted annually be the end of January or when applying for Connection.

DRC.7.9.5 The following Standard Planning Data are requested depending on the auxiliary transformer connection type and Generating module type:

(a) <u>Fault infeeds via Unit Transformers</u>

A submission should be made for each Generating Unit with an associated Unit Transformer. Where there is more than one Unit Transformer associated with a Generating Unit, a value for the total infeed through all Unit Transformers should be provided. The infeed through the Unit Transformer(s) should include contributions from all motors normally connected to the Unit Board, together with any generation (eg Auxiliary Gas Turbines) which would normally be connected to the Unit Board, and should be expressed as a fault current at the Generating Unit terminals for a fault at that location.

DATA DESCRIPTION	**UNITS**		**DATA FOR FUTURE YEARS**				
		Yr 0	**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**
Name of Power Station							
Number of Unit Transformer							
Symmetrical three phase short-circuit current infeed through the Unit Transformers(s) for a fault at the Generating Unit terminals:							
(a) at instant of fault	kA						
(b) after sub transient fault current contribution has substantially decayed	kA						
Positive sequence X/R ratio at instance of fault							
Sub transient time constant (if significantly different from 40ms)	ms						
Pre-fault voltage at fault point (if different from 1.0 p.u.)							

DATA DESCRIPTION	UNITS		DATA FOR FUTURE YEARS				
		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5
The following data items need only be supplied if the Generating Unit Step-up Transformer can supply zero sequence current from the Generating Unit side to the Transmission System							
Zero-sequencesource impedances as seen from the Generating Unit terminals consistent with the maximum infeed above:							
(a) Resistance	% on 100 MVA						
(a) Reactance	% on 100 MVA						

(b) Fault infeeds via Station Transformers

A submission is required for each Station Transformer directly connected to the Transmission System. The submission should represent normal operating conditions when maximum Generating Plant is Synchronized to the Transmission System, and should include the fault current from all motors normally connected to the Station Board, together with any Generation (e.g. Auxiliary Gas Turbines) which would normally be connected to the Station Board. The fault infeed should be expressed as a fault current at the HV terminals of the Station Transformer for a fault at that location.

If the submission for normal operating conditions does not represent the worst case, then a separate submission representing the maximum fault infeed that could occur in practice should be made.

DATA DESCRIPTION	**UNITS**		**DATA FOR FUTURE YEARS**				
		Yr 0	**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**
Name of Power Station							
Number of Station Transformer							
Symmetrical three phase short-circuit current infeed for a fault at the connection point:							
(a) at instant of fault	kA						
(b) after sub transient fault current contribution has substantially decayed	kA						
Positive sequence X/R ratio at instance of fault							
Sub transient time constant (if significantly different from 40ms)	ms						
Pre-fault voltage at fault point (if different from 1.0 p.u.)							
The following data items need only be supplied if the Generating Unit Step-up Transformer can supply zero sequence current from the Generating Unit side to the Transmission System							
Zero-sequencesource impedances as seen from the							

DATA DESCRIPTION	UNITS		DATA FOR FUTURE YEARS				
		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5
Point of Connection consistent with the maximum Infeed above:							
(a) Resistance	% on 100 MVA						
(b) Reactance	% on 100 MVA						

Note: The pre-fault voltage provided above should represent the voltage within the range 0.95 to 1.05 that gives the highest fault current

(c) <u>Fault infeeds from Power Park Modules</u>

A submission is required for the whole Power Park Module and for each Power Park Unit type. The submission shall represent operating conditions that result in the maximum fault infeed. The fault current from all motors normally connected to the Power Park Unit's electrical system shall be included. The fault infeed shall be expressed as a fault current at the terminals of the Power Park Unit, and the Connection Point, or User System Entry Point if Embedded, for a fault at the Connection Point, or User System Entry Point if Embedded.

For a Power Park Unit and a Power Park Module, where a manufacturer's data & performance report exists in respect of the model of the Power Park Unit, the User may opt to reference the manufacturer's data & performance report as an alternative to the provision of fault infeed data.

DATA DESCRIPTION	UNITS	DATA FOR FUTURE YEARS					
		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5
Name of Power Station							

DATA DESCRIPTION	UNITS	DATA FOR FUTURE YEARS					
		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5
Name of Power Park Module							
Power Park Unit type							
A submission shall be provided for the contribution of the entire Power Park Module and each type of Power Park Unit to the positive, negative and zero sequence components of the short circuit current at the Power Park Unit terminals and Grid Entry Point or User System Entry Point if Embedded for *(a)* a solid symmetrical three phase short circuit; *(b)* a solid single phase to earth short circuit; *(c)* a solid phase to phase short circuit; *(d)* a solid two phase to earth short circuit at the Grid Entry Point or User System Entry Point if Embedded.							
If protective controls are used and active for the above conditions, a submission shall							

DATA DESCRIPTION	UNITS	DATA FOR FUTURE YEARS					
		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5
be provided in the limiting case where the protective control is not active. This case may require application of a non-solid fault, resulting in a retained voltage at the fault point.							
A continuous time trace and table showing the root mean square of the positive, negative and zero sequence components of the fault current from the time of fault inception to 150ms after fault inception at 10ms intervals	Graphical and tabular kA versus ms						
For Power Park Units that utilise a protective control, *(a)* additional resistance applied to the Power Park Unit under a fault situation; *(b)* additional reactance applied to the Power	% on MVA % on MVA p.u. versus ms						

DATA DESCRIPTION	UNITS	DATA FOR FUTURE YEARS					
		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5
Park Unit under a fault situation; *(c)* A continuous time trace and table showing the root mean square of the positive, negative and zero sequence components of retained voltage at the fault point, if appropriate							
Active Power generated pre-fault	MW						
Power Factor (lead or lag)							
Pre-fault voltage (if different from 1.0 p.u.) at fault point (See note 1)	p.u.						
Items of reactive compensation switched in pre-fault							
Note 1. The pre-fault voltage provided above should represent the voltage within the range 0.95 to 1.05 that gives the highest fault current							

DRC.7.9.6 All of the above data items shall be provided in accordance with the following provisions:

(a) The value for the X/R ratio must reflect the rate of decay of the DC component that may be present in the fault current and hence that of the sources of the initial fault current. All shunt elements and loads must therefore be deleted from any system model before the X/R ratio is calculated.

(b) In producing the data, the User may use "time step analysis" or "fixed-point-in-time analysis" with different impedances.

DRC.7.10 DRC Planning Schedule 9 – Generation Reliability Standard Data

DRC.7.10.1 The DRC Schedule comprises a list of the data to be used by the Single Buyer in carrying out studies in relation to the Generation reliability Standard.

DRC.7.10.2 Single Buyer is the responsible party for the data and the recipient of the data.

DRC.7.10.3 The Schedule is applicable to the following class of User:

(a) Generators;

(b) Energy Storage Operators

DRC.7.10.4 The Data shall be submitted annually in January.

DRC.7.10.5 The Generation Reliability Standard Data shall contain:

(a) <u>For thermal unit:</u>

(i) Plant name;

(ii) Unit number;

(iii) Commissioning (date, month, year);

(iv) Retirement (date, month, year);

(v) Type of unit (steam coal/gas/etc., gas turbine, combined cycle, nuclear);

(vi) Rated/Nameplate capacity (gross & net in MW for main/alternate/standby fuel);

(vii) Configuration of plant for combined cycle;

(viii) Maximum available output/dependable capacity/net capacity in MW (for main/alternate/standby fuel);

(ix) Maximum & minimum generation in MW during emergency;

(x) Minimum output in MW under frequency-sensitive mode (for main/alternate/standby fuel);

(xi) Minimum output in MW without frequency-sensitive mode(for main/alternate/standby fuel);

(xii) Auxiliary power consumption;

(xiii) Forced outage rate (%);

(xiv) Minimum downtime;

(xv) Unit heat rate characteristics showing heat rate in mbtu/kWh at different load levels (at maximum, minimum and at 50%, 60%, 70%, 80%, 90% for main/alternate/standby fuel);

(xvi) Fuel data (for main, alternate and standby fuel):

(xvii) fuel type;

(xviii) fuel units;

(xix) fuel heat content (mbtu/unit);

(xx) fuel limits (maximum and minimum per day);

(xxi) fuel cost (RM/mbtu);

(xxii) Generating Unit maintenance schedule (day, week, year, period of outages & classification);

(xxiii) Detail of Fixed O&M cost (RM/kW-month) and detail of Variable O&M cost (RM/MWh);

(xxiv) Unit start up and shutdown characteristics- ramp rates, cold/hot/warm start up times and fuel consumption and cost during start up and shutdown;

(xxv) Emission rates for SO2, NO2 & CO2 (% weight of fuel in kTon);

(xxvi) Frequency response characteristic of each generation unit;

(xxvii) Plants layout showing all essential components;

(xxviii) Maximum fuel capacity storage & nominal level of fuel stored;

(xxix) Plants history: efficiency, trippings, planned & unplanned outages;

(xxx) EIA reports including all emission reports.

(b) <u>For Hydro Unit:</u>

(i) Plant name;

(ii) Unit number;

(iii) Maximum capacity in MW (rated/ nameplate capacity per unit);

(iv) Minimum capacity in MW per unit;

(v) Commissioning date for each unit;

(vi) Retirement date for each unit;

(vii) Type of generation (run-of-river, pondage, pumped storage, etc);

(viii) Forced outage rate in %;

(ix) Peak load and energy output schedules (weekly, monthly, annual) and minimum generation;

(x) Maintenance outages (day, month, year and period);

(xi) Daily storage capacity for pumped storage and pondage hydro (level & hours);

(xii) Minimum and maximum reservoir capacity for pumped storage and conventional hydro;

(xiii) Pumping capacity in MW for pumped storage hydro;

(xiv) Detail of Fixed O&M cost and detail of Variable O&M cost in RM/kW-month;

(xv) Monthly historical inflow energy for last 30 years;

(xvi) Cycle efficiency for pump storage (%);

(xvii) Plant performance characteristics and Rule Curve for the pondage, riparian flow;

(xviii) Detailed EIA reports.

(c) <u>For Energy Storage Unit:</u>

(i) Plant name;

(ii) Unit number;

(iii) Sizing capacity in MW (rated/ nameplate capacity per unit); Beginning of Life / End of Life

(iv) Sizing capacity in MWh (rated/ nameplate capacity per unit);; Beginning of Life / End of Life

(v) Capacity at Point of Connection in MW (rated/ nameplate capacity per unit); Beginning of Life / End of Life

(vi) Capacity at Point of Connection in MWh (rated/ nameplate capacity per unit);; Beginning of Life / End of Life

(vii) Commissioning date for each unit;

(viii) Retirement date for each unit;

(ix) Forced outage rate in %;

(x) Minimum State of Charge (MW);

(xi) Maximum State of Charge (MW);

(xii) Maximum slope in charge and discharge (MW/s);

(xiii) Maintenance outages (day, month, year and period);

(xiv) Detail of Fixed O&M cost and detail of Variable O&M cost in RM/kW-month.

DRC.7.11 DRC Planning Schedule 10 – Planning Data from the Grid Owner

DRC.7.11.1 The DRC Schedule comprises a list of the Network Data to be used by a User to model the Grid System, and cover the following ten (10) years.

DRC.7.11.2 Grid Owner is the responsible party for the data provided to the Users, who are the recipients of the data.

DRC.7.11.3 The Schedule is applicable to the Grid Owner:

DRC.7.11.4 The Data shall be submitted annually in December.

DRC.7.11.5 The Network Data shall contain:

(a) symmetrical three-phase short circuit current infeed at the instant of fault from the Grid System, (I1");

(b) symmetrical three-phase short circuit current from the Grid System after the sub transient fault current contribution has substantially decayed, (I1');

(c) the zero-sequence source resistance and reactance values at the Point of Connection, consistent with the maximum infeed below;

(d) the pre-fault voltage magnitude at which the maximum fault currents were calculated;

(e) the positive sequence X/R ratio at the instant of fault;

(f) the negative sequence resistance and reactance values of the Grid System seen from the Point of Connection, if substantially different from the values of positive sequence resistance and reactance which would be derived from the data provided above;

(g) if requested by the User, and for Multiple Point of Connection only, the initial positive sequence resistance and reactance values of the two (or more) sources and the linking impedance(s) derived from a fault study constituting the (π) (pi) equivalent and evaluated without the User network and load; and

(h) if requested by the User, and for Multiple Point of Connection only, the corresponding zero sequence impedance values of the (π) (pi) equivalent.

DRC.7.11.6 To enable the model to be constructed, the Grid Owner shall provide data based on the following conditions:

(a) The initial symmetrical three phase short circuit current and the transient period three phase short circuit current will normally be derived from the fixed impedance studies. The latter value should be taken as applying at times of 120ms and longer. Shorter values may be interpolated using a value for the sub transient time constant of 40ms. These fault currents will be obtained from a full System study based on load flow analysis that takes into account any existing flow across the point of connection being considered.

(b) Since the equivalent will be produced for the 500kV or 275kV parts of the Grid System, the Grid Owner will provide the appropriate supergrid transformer data.

(c) The positive sequence X/R ratio and the zero sequence impedance value will correspond to the Grid Owner source network only, that is with the section of network if any with which the equivalent is to be used excluded. These impedance values will be derived from the condition when all Generating Units are Synchronized to the Grid System or a User's System and will take account of active sources only including any contribution from the load to the fault current. The passive component of the load itself or other system shunt impedances should not be included.

(d) A User may at any time, in writing, specifically request for an equivalent to be prepared for an alternative System condition, for example where the User's System peak does not correspond to the Grid System peak, and the Grid Owner will, insofar as such request is reasonable, provide the information as soon as reasonably practicable following the request.

DRC.7.12 Additional Planning Data requirements

DRC.7.12.1 Notwithstanding the Standard Planning Data and Detailed Planning Data set out in this Section DRC7, as new types of configurations and operating arrangements of Power Stations emerge in future, the Grid Owner and GSO may reasonably require additional data to correctly represent the performance of such Plant and Apparatus on the System, where the present data submissions would prove insufficient for the purpose of producing meaningful System studies for the relevant parties.

DRC.8 Schedules of Operational Data to be submitted

DRC.8.1 DRC Operational Schedule 1 – Availability Declaration, Unit Scheduling and Dispatch Parameters

DRC.8.1.1 The DRC Schedule comprises data required with respect to Dispatch Units to be supplied pursuant to SDC1. Many of these parameters are the same as those required in DRC7.4, but the data supplied for planning will not be used for real time operation.

DRC.8.1.2 Single Buyer is the responsible party for the data and the recipient of the data.

DRC.8.1.3 The Schedule is applicable to the following class of User:

(a) Generators;

(b) Energy Storage Operators;

(c) Aggregators;

(d) Distributors;

(e) Network Operators.

DRC.8.1.4 The Data shall be submitted each Working Day by 1000 hours. Such Availability Declaration (respectively Unit Scheduling and Dispatch Parameters) will replace any previous Availability Declaration (respectively Unit Scheduling and Dispatch Parameters) covering any part of the next following Availability Declaration period (respectively Unit Scheduling and Dispatch Parameters period). In so far as not revised, the previously submitted Availability Declaration (respectively Unit Scheduling and Dispatch Parameters) shall apply for the next following Availability Declaration period (respectively Unit Scheduling and Dispatch Parameters period).

DRC.8.1.5 The following data shall be provided for the next following period (following day or days) as stated in SDC1.2.1 and from 0000 hours to 2400 hours for each day:

(a) For Generators:

(i) Availability Declaration:

(a) CDGU availability, (MW, start time and date, ancillary services limits) for each time period;

(b) Dispatch Unit regime unavailability, (day, start time, end time);

(c) Dispatch Unit start-up time;

(d) Loading blocks in MW following Synchronisation where applicable;

(e) Loading and de-loading ramp rates;

(f) MW and Mvar capability limits within which the CDGU is able to operate as shown in the relevant Generator Performance Chart;

(g) Minimum Generation capability is required to be confirmed if there has been any change since the last Availability Notice. Where required by the GSO, two-shifting limitations (limitations on the number of start-ups per Schedule Day) as follows:

(a) Maximum Loading ramp rates for the various levels of warmth and for up to two output ranges including soak times where appropriate;

(b) Maximum De-Loading ramp rates for up to two output ranges;

(c) Maximum number of on-Load cycles per twenty four (24) hour period, together with the maximum Load increases involved.

(h) Primary, Alternate and/or Stand-by fuel stock; and

(i) Reservoir lake level.

(ii) Unit Scheduling and Dispatch Parameters:

(a) CDGU inflexibility (inflexibility description, start date and time, end date and time, MW. The inflexibility can only be a minimum MW level or an exact MW level);

(b) Station Synchronizing interval;

(c) Station De-Synchronizing Intervals;

(d) CDGU Basic Data:

(a) Minimum Generation;

(b) Spinning Reserve Level (relates to Reserve capability as per OC3);

(c) Minimum Shutdown time;

(e) CDGU Two Shifting Limit;

(f) CDGU loading rates (up to three rates);

(g) CDGU loading rate MW breakpoints (up to two breakpoints);

(h) CDGU deloading rates (up to three rates with up to two MW breakpoints);

(i) CDGU loading rates (up to three rates with up to two MW breakpoints covering the range from Minimum Generation to CDGU Registered Capacity);

(j) CDGU de-loading rates (up to three rates with up to two MW breakpoints covering the range from Minimum Generation to CDGU Registered Capacity);

(k) Additional Generation reduction in MVAr generation capability; and

(l) Additional Generation - confirmation of ability to operate in Frequency Sensitive mode.

(m) For CCGT Module: CCGT Module matrix (example below) which is designed to achieve certainty in knowing the number of CCGT Units synchronized to achieve a Dispatch instruction.

CCGT Module Matrix example

CCGT MODULE	**CCGT GENERATING UNITS** AVAILABLE								
OUTPUT USABLE	1st GT	2nd GT	3rd GT	4th GT	5th GT	6th GT	1st ST	2nd ST	3rd ST
	OUTPUT USABLE								
MW	150	150	150				100		
0MW to 150MW	U								
151MW to 250MW	U						U		
251MW to 300MW	U	U							
301MW to 400MW	U	U					U		
401MW to 450MW	U	U	U						
451MW to 550MW	U	U	U				U		

(n) For Power Park Module: Power Park Module Availability Matrix showing the number of each type of Power Park Units expected to be available is illustrated in the example form below. The Power Park Module Availability Matrix is designed to achieve certainty in knowing the number of Power Park Units Synchronized to meet the Availability Declaration and Scheduling requirements. The Power Park Module Availability Matrix may have as many columns as are required to provide information on the different make and model for each type of Power Park Unit in a Power Park Module and as many rows as are required to provide information on the Power Park Modules within each Power Station. The description is required to assist identification of the Power Park Units within the Power Park Module and correlation with data provided under the Planning Code.

Power Park Module Planning Matrix Example Form

<table>
<tr><td colspan="4">Power Station [unique identifier]</td></tr>
<tr><td colspan="4">Power Park Module [unique identifier]</td></tr>
<tr><td rowspan="2">Power Park Unit Availability</td><td colspan="3">Power Park Units</td></tr>
<tr><td>Unit A</td><td>Unit B</td><td>Unit C</td></tr>
<tr><td>Description (make/model)</td><td></td><td></td><td></td></tr>
<tr><td>Output Usable (MW)</td><td></td><td></td><td></td></tr>
</table>

(iii) Other relevant Data:

(a) details of any special factors which in the reasonable opinion of the Generator may have a material effect or present an enhanced risk of a material effect on the likely output of such CDGUs. Such factors may include risks or potential interruptions to CDGU fuel supplies or developing plant problems. This information will normally only be used to assist in determining the appropriate level of Operating Reserve that is required under OC3;

(b) any temporary changes, and their possible duration, to the Registered Data of such CDGU;

(c) any temporary changes, and their possible duration, to the availability of Ancillary Services;

(d) details of any CDGU's commissioning or recommissioning or changes in the commissioning or recommissioning programs submitted earlier.

(b) <u>For Energy Storage Operators:</u>

(i) Availability Declaration stating whether or not it is proposed to be available in respect of each time period:

(a) for import or export of energy and at what wattage, expressed in a whole number of MW;

(b) for provision of Ancillary Services and what limits will apply for such Ancillary Services

(ii) Unit Scheduling and Dispatch Parameters

(iii) Other Relevant Data:

(a) details of any special factors which in the reasonable opinion of the Energy Storage Unit may have a material effect or present an enhanced risk of a material effect on the likely output of such Energy Storage Unit

(b) any temporary changes, and their possible duration, to the Registered Data of such Energy Storage Unit;

(c) any temporary changes, and their possible duration, to the availability of Ancillary Services;

(d) details of any Energy Storage Unit's commissioning or recommissioning or changes in the commissioning or recommissioning programmes submitted earlier.

(c) <u>For Aggregators:</u>

(i) Availability Declaration stating whether or not it is proposed to be available and in respect of each time period:

(a) for energy and at what wattage, expressed in a whole number of MW;

(b) for provision of Ancillary Services and what limits will apply for such Ancillary Services

(ii) Unit Scheduling and Dispatch Parameters

(iii) Other Relevant Data:

(a) details of any special factors which in the reasonable opinion of the Aggregator may have a material effect or present an enhanced risk of a material effect on the likely output of such aggregated units;

(b) any temporary changes, and their possible duration, to the Registered Data of such Aggregator;

(c) any temporary changes, and their possible duration, to the availability of Ancillary Services.

(d) <u>For Distributors:</u>

(i) Availability Declaration:

(a) constraints on its Distribution Network which the Single Buyer may need to take into account;

(b) the requirements of voltage control and MVAr reserves which the GSO may need to take into account for Grid System security reasons;

(c) the forecast of embedded production on its Distribution Network.

(e) <u>For Network Operators:</u>

(i) Availability Declaration:

(a) constraints on its Network which the Single Buyer may need to take into account;

(b) the requirements of voltage control and MVAr reserves which the GSO may need to take into account for Grid System security reasons;

(c) the forecast of embedded production on its Network.

DRC.8.2 DRC Operational Schedule 2 – Provisional Outage Schedules

DRC.8.2.1 The DRC Schedule comprises information relating to the Outages Schedules of the Users for Year 1 pursuant to OC2.

DRC.8.2.2 GSO is the responsible party for the data and the recipient of the data.

DRC.8.2.3 The Schedule is applicable to the following class of User:

(a) Generators for Provisional Generator Outage Schedules;

(b) Grid Owner for Provisional Transmission Outage Schedules;

(c) Energy Storage Operators for Provisional Outage Schedules;

(d) Aggregators for Planned Availability;

(e) Network Operators and Distributors for Provisional Outage Schedules;

(f) Grid Connected Customer for Provisional Outage Schedules.

DRC.8.2.4 The Data shall be submitted annually by the end of June of Year 0. If a User fails to submit data when required, the GSO will consider no outage is scheduled. Following submission of the data, the Users shall inform the GSO the details of any changes made to the information as soon as practicable.

DRC.8.2.5 Users shall provide for Year 1:

(a) For Generators, a "Provisional Generator Outage Schedule" taking account of the Generation Outage Plan described in OC2.3 and containing the following information:

(i) type of outages for each Generating Module;

(ii) the period of each outage consistent with the Outage Plan;

(iii) any other outages as required by statutory organizations or for statutory reasons;

(iv) the impact of the outages on the availability of the Ancillary Services provided according to the relevant Agreement;

(v) Identity of the Generating Modules;

(vi) MW not available;

(vii) Other Apparatus affected by the same outage;

(viii) Duration of outage;

(ix) Preferred start and end date;

(x) Statement on whether the planned outage is flexible or not; If so, provision of the earliest start date and latest finishing date;

(xi) Provision of details about any test which may affect the performance of the Grid System or the GSO's Outage Plan or risk of tripping.

(b) For Grid Owner, Network Operators and Distributors, and Grid Connected Customers, a "Provisional Outage Schedule" taking account of the Transmission Outage Plan described in OC2.4 and containing the following information:

(i) type of transmission outages;

(ii) the period of each outage consistent with the Outage Plan; and

(iii) any other outages as required by statutory organisations or for statutory reasons;

(iv) Start and end date and time of the outage;

(v) minimum required time to restore back the equipment, in case of emergency cancellation requested by GSO;

(vi) details about proposed outages of transmission equipment on Grid System;

(vii) details about any trip testing and risk of any transmission equipment trip associated with each trip test;

(viii) details about identifiable risk of transmission equipment trip arising from the work carried during the outage; and

(ix) other information known to the Grid Owner which may affect the reliability and security of the Grid System.

(c) <u>For Energy Storage Operators, a "Provisional Outage Schedule" containing the following information:</u>

(i) details of proposed outages on their Systems which may affect the performance of the Grid System;

(ii) details of any trip testing and risk of it causing trip of any transmission equipment in the Grid System;

(iii) other information known to the Energy Storage Unit which may or may affects the reliability and security of the Grid System;

(iv) the impact of the outages on the availability of the Ancillary Services provided according to the relevant Agreement.

(d) <u>For Aggregators, a "Planned Availability" containing the following information:</u>

(i) availability of the Demand Response service;

(ii) amount of MW available as part of the Demand Response service;

(iii) any specific conditions or constraints related to the implementation of the Demand Response service.

DRC.8.3 DRC Operational Schedule 3 – Indicative Outage Schedules

DRC.8.3.1 The DRC Schedule comprises information relating to the Outages Schedules of the Users for Year 2 up to Year 5 pursuant to OC2.

DRC.8.3.2 GSO is the responsible party for the data and the recipient of the data.

DRC.8.3.3 The Schedule is applicable to the following class of User:

(a) Generators excluding Power Park Modules for Indicative Generator Outage Schedules;

(b) Grid Owner for Indicative Transmission Outage Schedules.

DRC.8.3.4 The Data shall be submitted annually by the end of June of Year 0. If a User fails to submit data when required, the GSO will consider no outage is scheduled. Following submission of the data, the Users shall inform the GSO about the details of any changes made to the information as soon as practicable.

DRC.8.3.5 Users shall provide for Year 2 up to Year 5:

(a) <u>For Generators other than Power Park Modules, an “Indicative Generator Outage Schedule” containing the following information for each planned outage:</u>

(i) identity of the Generating Modules;

(ii) MW not available;

(iii) other Apparatus affected by the same outage;

(iv) duration of outage;

(v) preferred start and end date;

(vi) statement on whether the planned outage is flexible or not; if so, provision of the earliest start date and latest finishing date;

(vii) statement on whether the planned outage is due to statutory obligation (for example for pressure vessel inspection/boiler check); If so, the latest date the outage must be taken; and

(viii) provision of details about any test which may affect the performance of the Grid System or the GSO’s Outage Plan or risk of tripping.

(b) For Grid Owner, an "Indicative Transmission Outage Schedule" containing the following information:

(i) start and end date and time of the outage;

(ii) minimum required time to restore back the equipment, in case of emergency cancellation requested by GSO;

(iii) details about proposed outages of transmission equipment on Grid System;

(iv) details about any trip testing and risk of any transmission equipment trip associated with each trip test;

(v) details about identifiable risk of transmission equipment trip arising from the work carried during the outage; and

(vi) other information known to the Grid Owner which may affect the reliability and security of the Grid System.

DRC.8.4 DRC Operational Schedule 4 – Request for unplanned outages

DRC.8.4.1 The DRC Schedule comprises information on the changes to the Outages Schedules requested by a User or by the Grid Owner, which are considered as unplanned outages. Later changes are considered as emergency or forced outages and are treated in OC2.3.2 and OC2.4.2.

DRC.8.4.2 GSO is the responsible party for the data and the recipient of the data.

DRC.8.4.3 The Schedule is applicable to the following class of User:

(a) Generators;

(b) Grid Owners;

(c) Distributors;

(d) Network operators;

(e) Grid Connected users.

DRC.8.4.4 The Data shall be submitted as early as possible and at least:

(a) One (1) month before the effective start of the planned outage for 275 kV and 500 kV transmission outages;

(b) One (1) week before the effective start of the planned outage for 132 kV transmission outages;

(c) Seventy-two (72) hours before the effective start of the planned outage for generation outages.

DRC.8.4.5 The request for changes shall at least contain the following data:

(a) full details of all Plant and Apparatus affected by temporary capacity restrictions;

(b) the expected start date and start time of the Unplanned Outage;

(c) the estimated return to service time and date of the Plant and Apparatus affected, and the time and date of the removal of any temporary capacity restrictions; and

(d) details about possible restrictions, or risk of trip, on other Plant and Apparatus due to the Unplanned Outage.

DRC.8.5 DRC Operational Schedule 5 – User's (other than Generators) Demand Profiles and Active Energy Data

DRC.8.5.1 The DRC Schedule comprises information relating to the User's total Demand and Active Energy taken from the Transmission System at the Connection Point for Year 1 up to Year 5 pursuant to OC1.

DRC.8.5.2 Single Buyer is the responsible party for the data and the recipient of the data.

DRC.8.5.3 The Schedule is applicable to the following class of User:

(a) Grid connecter Customers;

(b) Distributors;

(c) Network Operators;

(d) Energy Storage Operators.

DRC.8.5.4 The Data shall be submitted annually by the end of June.

DRC.8.5.5 Demand and Active Energy data should relate to the point of connection to the Transmission System and shall differentiate, whenever applicable, between the data related to load and the data related to Embedded Generation. For Year 1 up to Year 5, the following data shall be provided:

(a) The half hour Active and Reactive Power forecast Demand profiles for the day of that User's maximum Demand.

(b) The half hour Active and Reactive Power forecast Demand for the annual Peninsular Malaysia Maximum Demand.

(c) The half hour Active and Reactive Power forecast Demand for the annual Peninsular Malaysia Minimum Demand.

(d) The annual Active Energy requirements for Average Conditions. Note for Network Operators: Demand profiles and Active Energy data should be for the Power System of the Network Operator, including all Connection Points. Demand Profiles should give the numerical maximum demand that in the User's opinion could reasonably be imposed on the Transmission System.

DATA DESCRIPTION	**Yr 0**	**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**DATA CAT**
DEMAND PROFILES							
Total User's system profile (please delete as applicable)	Day of User's annual Maximum Demand (MW) Day of annual peak of Power System Demand (MW)						

	Day of annual minimum Power System Demand (MW)						
0000 – 0030							CPD
0030 – 0100							and
0100 – 0130							OC1
0130 – 0200							“
0200 – 0230							“
0230 – 0300							“
0300 – 0330							“
0330 – 0400							“
0400 – 0430							“
0430 – 0500							“
0500 – 0530							“
0530 – 0600							“
0600 – 0630							“
0630 – 0700							“
0700 – 0730							“
0730 – 0800							“
0800 – 0830							“
0830 – 0900							“
0900 – 0930							“
0930 – 1000							“
1000 – 1030							“
1030 – 1100							“
1100 – 1130							“

1130 : 1200							“
1200 : 1230							“
1230 : 1300							“
1300 : 1330							“
1330 : 1400							“
1400 : 1430							“
1430 : 1500							“
1500 : 1530							“
1530 : 1600							“
1600 : 1630							“
1630 : 1700							“
1700 : 1730							“
1730 : 1800							“
1800 : 1830							“
1830 : 1900							“
1900 : 1930							“
1930 : 2000							“
2000 : 2030							“
2030 : 2100							“
2100 : 2130							“
2130 : 2200							“
2200 : 2230							“
2230 : 2300							“
2300 : 2330							“
2330 : 0000							“

							“

DATA DESCRIPTION	Out-turn		Yr 0	Yr 1.	Yr 2	Yr 3	Yr 4	Yr 5
	Actual	Weather correction						
Active Energy Data								
Total annual Active Energy requirements under Average Conditions of each User in the following categories:-								
Domestic								
Farms								
Commercial								
Industrial								
Traction								
Lighting								
User System Losses								
Off-Peak:-								
Domestic								
Commercial								

DRC.8.6 DRC Operational Schedule 6 – Generator's forecast Demand

DRC.8.6.1 The DRC Schedule comprises information relating to the Generator's total Demand and Active Energy taken from the Grid System at the Connection Point for Year 1 pursuant to OC1.

DRC.8.6.2 Single Buyer is the responsible party for the data and the recipient of the data.

DRC.8.6.3 The Schedule is applicable to the Generators connected to the Grid System.

DRC.8.6.4 The Data shall be submitted annually by the end of June.

DRC.8.6.5 For Year 1, the following data shall be provided:

(a) Average and max forecast Demand at the respective Metering Point. Such Demand could be associated with auxiliary and start-up loads supplied directly from the Grid System;

(b) The annual Active Energy requirements for Average Conditions.

DRC.8.7 DRC Operational Schedule 7 – Demand Response Availability Declaration

DRC.8.7.1 The DRC Schedule comprises information relating to the Availability Declaration of Demand Response pursuant to SDC1.

DRC.8.7.2 Single Buyer is the responsible party for the data and the recipient of the data.

DRC.8.7.3 The Schedule is applicable to the following class of User:

(a) Aggregators;

(b) Grid Connected Customers.

DRC.8.7.4 The Data shall be submitted every Scheduling Day by 1000 hours.

DRC.8.7.5 The following Data shall be provided for the next following period (following day or days) as stated in SDC1.5.1 and from 0000 hours to 2400 hours for each day:

(a) demand in discrete MW blocks that can be made available for control and the times when this control may be exercised;

(b) the notice required for each discrete MW block to be switched out and subsequently switched back in; and

(c) the price for each discrete MW block as specified in the relevant Agreement.

<End of the Data Registration Code Main Text>

Metering Code (MC)

MC.1 Preamble

MC.1.1 The Grid Code is a code developed and issued by the Commission. The Grid Code is composed by a Main Code, containing the main provisions structuring the purpose, the scope, the governance and some general requirements, and by additional codes, containing the specific technical rules for different subjects related to the operation of the Grid system.

MC.1.2 According to section 50A of the Electricity Supply 1990 [*Act 447*], the Commission may develop and issue such additional codes as it deems fit and expedient or the Minister may direct from time to time, as the case may be.

MC.2 Amendment

MC.2.1 The Commission may at any time amend, modify, vary or revoke this Code or any part thereof.

MC.3 Introduction, Objectives and Scope

MC.3.1 The provisions of sections MMC.1, MMC.2 and MMC.3 of the Main Code shall apply to this Metering Code.

MC.4 Requirements

MC.4.1 General

MC.4.1.1 Revenue Metering shall be installed to measure Active Energy and Reactive Energy and Active Power and Reactive Power at Connection Points and the nett output of each Generating Module or Energy Storage Unit on the Grid System. This shall comprise both Import and Export metering as required by the Single Buyer and specified in the relevant Agreement.

MC.4.1.2 The Revenue Metering shall be located as close as practicable to the Connection Point. Wherever there is a material difference between the Metering Installation location and the Connection Point an adjustment for the differences between the two locations will be calculated by the User in Agreement with the Single Buyer. The Metering Installation shall be capable of being interrogated both locally and remotely.

MC.4.1.3 The Revenue Metering Data for Active Energy, Reactive Energy, Active Power and Reactive Power shall be recorded, stored at data registers on-site every thirty (30) minutes and automatically collected once a day by the Data Collection System under the responsibility of the Single Buyer. The on-site electronic data registers shall have the capability to communicate with the automatic Data Collection System and adequate capacity to store at least forty-five (45) days of on-site data to provide back-up for any interruptions to the automatic Data Collection System.

MC.4.1.4 The Revenue Metering shall be the primary source of data for Billing purposes. Revenue Metering shall consist of a Main Meter to measure and record the required data and a Check Meter to validate the readings from the Main Meter and to serve as back-up metering in case of malfunction of the Main Meter at all Connection Points. For TPA Users, dedicated data management system shall be implemented for billing purposes to establish the settlement of its customers.

MC.4.1.5 The Revenue Metering Data that is collected by the automatic Data Collection System is required by the Single Buyer for Billing purposes. In the case of TPA users, the Revenue Metering Data that is collected by data management system must be implemented for billing purposes.

MC.4.1.6 The Metering CT and VT shall be used for Operational Metering where reasonably required by the GSO after consultation with the User so as to provide measurements of voltage, current, Active and Reactive Power. The Operational Metering Data shall be collected by the Remote Terminal Units

(RTUs) which are part of the GSO's SCADA system as described in Connection Code CC6.6.3.

MC.4.1.7 Installation of Operational Metering using Metering CT and VT shall be undertaken by the User, as soon as practicable following the request of the GSO. It shall be subject to appropriate testing on a joint basis with the User to ensure its functioning in the required manner for system control purposes. Users shall maintain the Operational Metering equipment.

MC.4.2 Key Principles

MC.4.2.1 The key principles for application of metering in this Metering Code are as follows:

(a) each User's Connection Point shall have a Metering Installation;

(b) each Connection Point to an External Interconnection shall have a Metering Installation;

(c) each Metering Installation shall consist of but shall not be limited to the following:

(i) Meters and associated Data Loggers;

(ii) current transformers (CT) and voltage transformers (VT);

(iii) secure protected wiring from current and voltage transformers to the Meters;

(iv) panel on which the Meters and associated Data Loggers are mounted;

(v) communication and communication interface equipment;

(vi) Metering accessories (for example, but not limited to, metering fuses, test blocks)

(vii) secure auxiliary supplies to Meters and other equipment;

(viii) monitoring and alarm equipment; and

(ix) facility to keep the installation secure, clean and dry;

as agreed between the GSO and the Single Buyer as the case may be and the User in the relevant Agreement.

(d) the accuracy of the Metering Installation and the parameters to be measured at each Connection Point shall be determined as indicated in Appendix 1;

(e) The person as nominated under the relevant Agreements shall have the responsibility for the provision of Metering Installations and spares as may be required, for Connection Points directly connected to the Grid System;

(f) All costs of the Metering Installation are covered as per the relevant Agreement;

(g) The party responsible for the Revenue Metering Installation is the Single Buyer;

(h) The Single Buyer shall:

(i) ensure that the Revenue Metering Installations and Check Metering Installations are provided, installed and maintained in accordance with Appendix 1;

(ii) ensure that the components, accuracy and testing of each of the Metering Installations complies with the requirements of this Metering Code;

(iii) where one of the Metering Installations is described as a Type 1 Metering Installation in Appendix 1 arrange for the provision of an alarm monitoring feature to cover any failure of any critical components of the Metering Installation including the reduction of voltage input and loss of auxiliary supplies;

(iv) coordinate the electronic accessibility of each Metering Installation in a manner as to prevent congestion during Metering Data collection.

(i) Metering Installations shall comply with this Metering Code and shall be:

(i) physically secure and protected from tampering;

(ii) registered with the Single Buyer;

(iii) capable of providing Metering Data for electronic transfer to the Metering Database of the Single Buyer;

(j) Energy Data shall be based on units of kilowatt-hours (kWh) (Active Energy) and kilovar-hours (kVArh) (Reactive Energy) and shall be collated at each Billing Period by the Single Buyer and validated in accordance with standard procedure according to the relevant Agreement;

(k) wherever required and installed in accordance with this Metering Code, Check Meters shall be used to provide Metering Data whenever the Main Metering fails;

(l) each Network Operator and User with a User System shall be entitled to receive Metering Data as recorded by the Single Buyer in respect of the Metering Points on their network or system;

(m) historical data shall be maintained in the Metering Database for;

(i) six (6) months on-line;

(ii) thirteen (13) months in accessible format; and

(iii) seven (7) years in archive;

(n) The Single Buyer shall be responsible for auditing Revenue Metering Installations including both Main Meter and Check Meter facilities and shall be accountable for the accuracy and reliability of the Metering infrastructure and for reporting the performance of the Metering system;

(o) The Single Buyer shall establish a registration process and a Metering Register to facilitate the application of this Metering Code to Users in respect of:

(i) new Metering Installations;

(ii) Modifications to existing Metering Installations; and

(iii) decommissioning of Metering Installations,

The Single Buyer will also provide information on matters such as application process, timing, relevant parties, fees and Metering Installation details;

(p) In relation to the provisions of this Metering Code, non-compliance will be dealt with by using the Request to Vary and Issue Process set out in the General Conditions GC9, GC10 and GC11 of the Grid Code.

MC.5 Ownership

MC.5.1 The person nominated under the relevant Agreement shall design, supply, install and test the Revenue Metering Installation at that Connection Point.

MC.5.2 If the Single Buyer does not own the premises where the Metering Installation is located, then the owner of that premises will provide:

(a) 24-hour access and adequate space for the Metering and associated communications equipment;

(b) reliable auxiliary power supplies; and

(c) current transformers (CT) and voltage transformers (VT) compliant with this Metering Code and as agreed by the Single Buyer

MC.5.3 In relation to a connection between the Grid System and a User System the ownership of each component of the Metering Installation shall be agreed in the relevant Agreement.

MC.6 Metering Accuracy and Data Exchange

MC.6.1 Metering Accuracy and Availability

MC.6.1.1 Each Metering Installation shall be capable of separately measuring the metered quantities in each direction where bi-directional Active Power and Reactive Power flows are possible.

MC.6.1.2 The class of Metering Installation and the associated accuracy requirements that must be installed at a specific Connection Point shall be determined in accordance with Appendix 1.

MC.6.1.3 A Check Metering Installation is required to have the same degree of accuracy as the Revenue Metering Installation.

MC.6.1.4 The target availability of measurement transformers and Metering Installations shall be 99% per annum and the target availability of the communication link shall be 95% per annum unless agreed otherwise between the Single Buyer and the User.

MC.6.1.5 The Metering Installation shall be in accordance with and conform to relevant Technical Specifications and Standards as agreed by the Single Buyer and included in the relevant Agreement. These Technical Specifications and Standards shall include:

(a) relevant Malaysian National Standards (MS);

(b) relevant International, European technical standards, such as IEC, ISO and EN; and

(c) other relevant national standards such as BS, DIN and ASA.

MC.6.2 Data Collection System

MC.6.2.1 The User or the Single Buyer as the case may be shall ensure that for each Metering Installation, the communication link and the associated equipment procured is approved under the relevant telecommunication laws and regulations and operated and maintained in accordance with the same laws and regulations.

MC.6.2.2 The Single Buyer shall establish appropriate processes and procedures for the collection of the Metering Data and its storage in the Metering Database.

MC.6.2.3 The rules and protocols in the use of Metering Installations and Data Collection Systems that form part of a Metering Installation must be of a type approved by the Single Buyer. The Single Buyer shall not unreasonably withhold such approval but may withhold approval if there is reasonable doubt in terms of adverse effects.

MC.6.2.4 Data formats used in the Data Collection System shall allow access to the Metering Data at a Metering Installation and from the Metering Database with the data being sent to the Single Buyer with a format approved by the Single Buyer.

MC.7 Commissioning, Inspection, Calibration and Testing

MC.7.1 Commissioning

MC.7.1.1 Where commissioning of new Metering equipment or a Modification to existing Metering equipment is required, the User shall notify the Single Buyer or the Single Buyer shall notify the User, as the case may be, and any Associated Users of the details of the new Metering Installation and Modifications to the existing Metering Installation at least one (1) calendar month prior to the commissioning date. The User also shall, prior to the commissioning, undertake inspection, calibration and component testing in accordance with this MC7 to ensure compliance of the Metering Installation with the provisions of the Metering Code and the requirements and procedures detailed in Appendix 2 of this Metering Code.

MC.7.2 Responsibility for Inspection, Calibration and Testing

MC.7.2.1 Inspection, calibration and testing of each Metering Installation shall be carried out in accordance with the inspection and testing requirements detailed in Appendix 2.

MC.7.2.2 A User shall make a reasonable request for testing of any Metering Installation and the Single Buyer shall not refuse any reasonable request.

MC.7.2.3 The Single Buyer must verify the results of all tests carried out in accordance with Appendix 2 recorded in the Metering Register in respect of each Metering Installation and shall arrange for sufficient audit testing of Metering Installation as the Single Buyer considers necessary for assessing whether the accuracy of each Metering installation complies with the requirements of this Metering Code.

MC.7.2.4 Each User shall provide the auditor of the Single Buyer with unrestricted access to each Metering Installation for which it is responsible for the purpose of the routine testing of such Metering Installation. The Single Buyer shall give notice in advance in accordance with the relevant Agreement for such testing and the notice shall specify:

(a) the name of the person who will be carrying out the testing on behalf of the Single Buyer; and

(b) the date of the test and the time at which the test is expected to commence and conclude.

MC.7.2.5 The auditor of the Single Buyer shall respect all of the User's safety and security requirements when conducting the audit tests on the Metering Installation.

MC.7.2.6 The Single Buyer shall make the Metering Installation test results available to any person as soon as practicable if that person is considered by the Single Buyer to have sufficient interest in the results.

MC.7.3 Procedures in the Event of Non-compliance

MC.7.3.1 In the event that the accuracy of the Metering Installation does not comply with the requirements of this Metering Code, the User shall:

(a) advise the Single Buyer within one (1) Business Day of the detection of such discrepancy and of the length of such discrepancy may have existed; and

(b) arrange for the accuracy of Metering Installation to be restored within a time agreed with the Single Buyer.

MC.7.3.2 The Single Buyer shall make appropriate corrections to the Metering Data to take into account the errors referred to in MC7.3.1 and to minimize adjustment to the final Billing account.

MC.7.4 Audit of Metering Data

MC.7.4.1 A User may request the Single Buyer to conduct an audit to determine the consistency between the Metering Data held in the Metering Database and the Metering Data held in the User's Metering Installation.

MC.7.4.2 If there are discrepancies between the Metering Data held in the Metering Database and the Metering Data held in the User's Metering Installation the affected Users (or Associated Users) shall together determine the most appropriate way of resolving the discrepancy.

MC.7.4.3 If there are discrepancies between the Metering Data held in the Metering Database and the Metering Data held in the User's Metering Installation the Metering Data in the Metering Installation shall be taken as prima facie evidence of the Metering Point energy data.

MC.7.4.4 The Single Buyer may carry out periodic, random or unannounced audits of Metering Installations to confirm compliance with this Metering Code. The Single Buyer shall be given unrestricted access to Metering Installations by all Users for the purpose of carrying such audits. The Single Buyer shall ensure that the person carrying out such audits respect the User's security and safety requirements.

MC.8 Security of Metering Installation and Data

MC.8.1 Security of Metering Equipment

MC.8.1.1 The Single Buyer shall ensure that the Metering Installation and associated communication links, interface circuits, information storage and processing systems are adequately secured by means of seals or other security devices. The seals or other security devices shall only be broken in the presence of representatives from the Single Buyer and representatives of the Associated Users as the case may be.

MC.8.1.2 The Single Buyer may audit the security measures applied to Metering Installations from time to time as it considers appropriate.

MC.8.1.3 The Single Buyer may override any of the security measures applied or devices fitted to a Metering Installation with prior notice to the Responsible Person.

MC.8.2 Security Control

MC.8.2.1 The Single Buyer shall ensure that the Metering Data held in the Metering Installation is protected from unauthorized direct local and remote electronic access by implementing suitable password and/or security measures.

MC.8.2.2 The Single Buyer shall hold a copy of the passwords referred to in MC8.2.1 in a secure and confidential manner.

MC.8.3 Changes to Metering Equipment, Parameters and Settings

MC.8.3.1 Changes to Metering equipment or to parameters or settings within a Metering Installation shall be —

(a) authorized by the Single Buyer prior to the change being made;

(b) confirmed to the Single Buyer by the User within two (2) Business Days after the changes have been made;

(c) recorded by the Single Buyer in the Metering Register

MC.8.3.2 Each User shall ensure that the Single Buyer is provided with alternative Metering Data acceptable to the Single Buyer while changes to the Metering equipment parameters and settings are being made.

MC.8.4 Changes to Metering Data

MC.8.4.1 Alterations to the original raw stored Metering Data in a Meter shall not be permitted. However, in the case of the on-site accuracy testing of a Metering Installation changes shall be permitted to the uploaded Metering Data by the Single Buyer following completion of the tests.

MC.9 Processing of Metering Data for Billing Purposes

MC.9.1 Metering Database

MC.9.1.1 The Single Buyer shall create, maintain and administer a Metering Database containing the Metering information required by this Metering Code for each metering installation registered with the Single Buyer. The Single Buyer may use agency databases to form part of the Metering Database.

MC.9.2 Remote Acquisition of Data

MC.9.2.1 The Single Buyer shall be responsible for the remote acquisition of the Metering Data and storing of such Metering Data in the Metering Database for Billing purposes in accordance with MC10.1. If remote acquisition becomes unavailable the Single Buyer shall make arrangements for an alternative means of obtaining the relevant Metering Data.

MC.9.3 Periodic Energy Metering

MC.9.3.1 Metering Data relating to the amount of Active Energy and where relevant to Reactive Energy passing through a Metering Installation shall be collated by Billing Periods unless otherwise agreed with a User by the Single Buyer.

MC.9.4 Data Validation and Substitution

MC.9.4.1 The Single Buyer shall be responsible for the validation and substitution of Metering Data and shall develop Metering Data validation and substitution processes in consultation with Users.

MC.9.4.2 Wherever available Check Metering Data shall be used by the Single Buyer to validate the Metering Data provided that the Check Metering Data has been appropriately adjusted for differences in Metering Installation accuracy.

MC.9.4.3 If a Check Meter is not available or the Metering Data cannot be recovered from the Metering Installation within the time required for Billing, then a substitute value is to be prepared by the Single Buyer using a method agreed between the Single Buyer and a User or as included in a relevant Agreement.

MC.9.4.4 Upon detecting a loss of Metering Data or incorrect Metering Data from a Metering Installation, the Single Buyer shall notify the relevant User within twenty-four (24) hours of the detection.

MC.9.5 Errors Found in Meter Tests, Inspections or Audits

MC.9.5.1 If errors in excess of those prescribed in Appendix 2 are demonstrated following a Metering Installation test, inspection or audit carried out in accordance with MC8, and the Single Buyer is not aware of the exact time in which the error arose, and except where there is contrary evidence, the error shall be deemed to have occurred at a time which is the shorter of the following:

(a) the time half way between the time of the most recent test or inspection which demonstrated that the Metering Installation complied with the relevant accuracy requirement and the time when the error was detected; or

(b) the time between the current billing period and one (1) month preceding the time when the error was detected; or

as otherwise agreed in accordance with the relevant Agreement.

MC.9.5.2 If a test or audit of a Metering Installation demonstrates a measurement error of less than two (2) times the error permitted by Appendix 2, no substitution of readings shall be required unless, in the reasonable opinion of the Single Buyer, a particular party would be significantly affected if no substitution were made.

MC.9.5.3 If any substitution is required under MC9.5.2, the Single Buyer must provide substitute readings to effect a correction for that error in respect of the period since the error was deemed to have occurred in accordance with MC9.5.1.

MC.10 Confidentiality

MC.10.1 Metering Data and the passwords are confidential data and shall be treated as confidential information in accordance with this Metering Code by all person bound by the Grid Code.

MC.11 Metering Installation Performance

MC.11.1 Metering Data shall be provided from each Connection Point for each Billing Period at a level of accuracy prescribed in Appendix 1 and with Metering Installation major component availability prescribed in MC6.1.4 unless otherwise agreed between the Single Buyer and the User.

MC.11.2 If a Metering Installation Outage or malfunction occurs, the User or the Single Buyer as the case may be, shall ensure that repairs are made to the Metering Installation as soon as practicable after becoming aware of the outage or malfunction and in any event within two (2) Business Days, unless an Exemption is agreed and obtained from the Single Buyer.

MC.11.3 Each User that becomes aware of the Metering Installation Outage or malfunction must advise the Single Buyer within one (1) Business Day of becoming aware of the malfunction.

MC.11.4 All Metering Installation and Data Logger clocks shall be referenced to the Malaysian Standard Time and maintain a standard of accuracy in accordance with Appendix 1 of this Metering Code.

MC.11.5 The Metering Database must be set within an accuracy of ±1 second of Malaysian Standard Time.

MC.12 Disputes

MC.12.1 Disputes concerning and in relation to this Metering Code shall be dealt with in accordance with the procedures set out in the General Conditions of this Grid Code.

<End of the Metering Code Main Text>

Metering Code Appendix 1 – Type and Accuracy of Revenue Metering Installations

MCA1.1 General requirements

MCA1.1.1 The following are the minimum requirements for Metering Installations. Users may install Metering Installations of a higher level of accuracy than that required. The full costs of such Metering Installations shall be borne by the User.

MCA1.1.2 The Current Transformers and Voltage Transformers shall be in accordance with IEC 61869-1, and

MCA1.1.3 The Current Transformers provided for Metering Installation shall be in accordance with IEC 61869-2.

MCA1.1.4 The Voltage Transformers provided for Metering Installation shall be in accordance with IEC 61869-3

MCA1.1.5 In the case of a combined measurement transformer (CT + VT), the combined measurement transformers provided for Metering Installation shall be in accordance with the IEC 61869-4.

MCA1.1.6 Metering Installations are classified based upon the annual energy and maximum power in accordance with the following table:

Type	Criteria (per Metering Point)
1	Maximum power ≥ 7.5 MW OR Annual energy ≥ 60 GWh
2	Maximum power < 7.5 MW AND Annual energy < 60 GWh

MCA1.2 Metering Installations Commissioned Prior to The Grid Code Effective Date

MCA1.2.1 The use of Metering class current transformers and voltage transformers that are not in accordance with Table 1 of MCA.1.3 are permitted provided that where necessary to achieve the overall accuracy requirements:

(a) of a Metering Installation of a higher accuracy class; and

(b) compensation factors are applied within the Meter to compensate for current and voltage transformer errors.

MCA1.2.2 Protection current transformers are acceptable as an interim measure where there are no suitable Metering class current transformers available provided the current consumption does not exceed 80% of the primary ratio and the overall accuracy and performance levels can be met.

MCA1.2.3 Where the requirements of MCA.1.2.1 and MCA.1.2.2 cannot be achieved then the User is required to comply with the transition arrangements agreed with the Single Buyer or obtain an Exemption from the Single Buyer or upgrade the Metering Installation to comply with this Appendix 1.

MCA1.2.4 Where Metering is installed at some point other than the defined Connection Point then the User shall provide the appropriate adjustment data to the Single Buyer for approval.

MCA1.2.5 New Metering Installations after the Grid Code Effective Date shall comply with this Metering Code.

MCA1.3 Specification Requirements for Metering Installations

MCA1.3.1 The following are the specification requirements of Metering Installation equipment for Type 1 and Type 2 Metering Installations:

Type	CT	VT	Meter Class		Meter Clock Error (Seconds) with Reference to Malaysian Standard Time
			Active	Reactive	
1	Ratio: Is/1A Class: 0.2 Burden: 30 VA	Class: 0.2 Burden: 50 VA (100 VA in case of shared load with burden above 10 VA)	0.2	0.5	±5ppm
2	Ratio: Is/1A Class: 0.2 Burden: 30 VA	Class: 0.2 Burden: 50 VA (100 VA in case of shared load with burden above 10 VA)	0.2	1	±5ppm

MCA1.4 Check metering

MCA1.4.1 Check Metering shall be applied in accordance with the following Table:

Type	Check Metering Requirement
1	Check Metering Installation
2	Check Metering

MCA1.4.2 A Check Metering Installation shall include the provision of a separate Metering Installation using separate current transformer cores and separate secondary windings. The accuracy of Check Metering Installation shall be the same as the Main Metering Installation.

MCA1.4.3 Wherever the Check Metering Installation accuracy level duplicates the Main Metering Installation accuracy level, the validated data set of the Main Metering Installation shall be used to determine the Energy Measurement. Where the Main Metering Installation data set cannot be validated due to errors in excess of those prescribed in this Appendix the provisions of MC9.5 shall apply.

MCA1.4.4 The physical arrangement of Check Metering shall be agreed between the Single Buyer and the User and recorded in the Connection Agreement.

MCA1.4.5 Check Metering Installation may be supplied from secondary circuits used for other purposes and may have a lower level of accuracy than Revenue Metering Installation as agreed between the Single Buyer and the User. The accuracy of Check Metering Installation shall not exceed twice the level prescribed in this Appendix 1 for the Revenue Metering Installation.

MCA1.5 Resolution and Accuracy of Displayed or Captured Data

MCA1.5.1 Any programmable settings available within a Metering Installation, Data Logger, or any peripheral device, that may affect the resolution of displayed or stored data, shall be set as agreed between the Single Buyer and the User in the relevant Agreement.

MCA1.5.2 The resolution of the energy registration of 0.5S class Meters shall be better than 0.2 % and the resolution of the energy registration of 0.2S class Meters shall be better than 0.1%.

MCA1.6 General Design Requirements and Standards

MCA1.6.1 The following requirements shall be incorporated in the design of each Metering Installation without limiting the scope of detailed design.

MCA1.6.2 For Type 1 Metering Installations, the current transformer core and the secondary wiring associated with the Revenue Meter shall not be used for any other purpose unless otherwise agreed by the Single Buyer.

MCA1.6.3 For Type 2 Metering Installations, the current transformer core and the secondary wiring associated with the Revenue Meter may be used for any other purposes (e.g., local Metering or protection). In such cases the User shall satisfactorily demonstrate to the Single Buyer and the GSO that the accuracy of the Metering Installation or other local Metering or protection shall not be compromised and suitable procedures and measures shall be put in place and implemented to protect the security of the Metering Installation as well as other local Metering or protection.

MCA1.6.4 At Metering Points where a voltage transformer with separate secondary windings is not provided then the voltage supply to each Metering Installation shall be separately fused and the fuses shall be located in an accessible position as close as practicable to the voltage transformer secondary winding. For the avoidance of doubt in every new Metering Installation, the voltage transformers shall have separate secondary windings for each Metering quantity or measurement. In each Metering Installation where more than one voltage transformer is installed on the same feeder circuit, a voltage change-over arrangement shall be included to enable continue voltage supply in case of failure of a voltage transformer.

MCA1.6.5 Secondary wiring in the Metering Installation shall be by the most direct route and the number of terminations shall be demonstrably kept to a minimum.

MCA1.6.6 The incidence and the magnitude of burden changes on any voltage and current transformer supplying the Metering Installation shall be demonstrably kept to a minimum.

MCA1.6.7 Wherever applicable the Meters, Data Loggers and Metering transformers in each new Metering Installation shall comply with the relevant IEC or equivalent standards. The burden of the Metering transformers shall have a burden rating with an extra 20% provision of the maximum burden calculated for the Metering Installation.

MCA1.6.8 Suitable Isolation facilities shall be provided to facilitate testing and calibration of each Metering Installation without any adverse effects

MCA1.6.9 All necessary drawings and supporting information providing details of the Metering Installation shall be available for efficient maintenance and audit purposes.

< Metering Code - End of Appendix 1>

Metering Code Appendix 2 - Commissioning, Inspection, Calibration and Testing Requirements

MCA2.1 General Requirements

MCA2.1.1 The User shall ensure that the Metering equipment to be purchased has been type tested to the standards referenced in this Metering Code and is compliant with this Metering Code and shall furnish type test certificates to the Single Buyer in accordance with the relevant Agreement.

MCA2.1.2 The User shall ensure that the equipment within a Metering Installation to be purchased has been tested under laboratory conditions to the required class accuracy according to international standards IEC 61869-2 for CT, IEC 61869-3 for VT and IEC 61869-4 for CT+VT. Appropriate test certificates shall be kept by the owner of the equipment.

MCA2.1.3 The Single Buyer shall ensure that commissioning and testing of the Metering installation is carried out:

(a) In accordance with this Appendix 2 of this Metering Code; or

(b) in accordance with a test plan that has been agreed and approved by the Single Buyer in consultation with the Grid Owner and the GSO; and

(c) to the same requirements as for new equipment where equipment is to be recycled for use in another site.

MCA2.1.4 Associated Users may witness the tests on request to the Single Buyer and no reasonable request shall be denied.

MCA2.1.5 The Single Buyer shall review the commissioning and testing requirements in this Appendix 2 of this Metering Code every five (5) years in accordance with equipment performance statistics and developing industry standards. Any proposed changes shall be submitted for discussion and approval at the Grid

Code Committee in accordance with the procedures outlined in General Conditions (GC) of this Grid Code.

MCA2.1.6 The Single Buyer shall provide the test results to the User in accordance with the relevant Agreement and to each Associated User upon request.

MCA2.1.7 Tables 1 and 2 summarise the accuracy requirements for Type 1 and Type 2 Metering Installations where:

(a) the method of calculating the overall error of the Metering Installation is by the vector sum of the errors of three major component parts constituting the Metering Installation that is the voltage transformer, the current transformer and the Meter; and

(b) compensation is applied then the resultant Metering Installation error should be as close to zero as practicable.

Table 1: Accuracy Requirements of Type 1 Metering Installation

% Rated Load	Power Factor					
	Unity	0.866 Lead		0.5 Lag		Zero
	Active	Active	Reactive	Active	Reactive	Reactive
10	0.7%	0.7%	1.4%	N/A	N/A	1.4%
50	0.6%	0.6%	1.0%	0.5%	1.0%	1.0%
100	0.6%	0.6%	1.0%	N/A	N/A	1.0%

Table 2: Accuracy Requirements of Type 2 Metering Installation

% Rated Load	Power Factor					
	Unity	0.866 Lead		0.5 Lag		Zero
	Active	Active	Reactive	Active	Reactive	Reactive
10	1.4%	1.4%	2.8%	N/A	N/A	2.8%
50	1.0%	1.0%	2.0%	1.5%	3.0%	2.0%

100	1.0%	1.0%	2.0%	N/A	N/A	2.0%

(Note: All measurements in Tables 1 and 2 are to be referred to 25degrees Celsius under Meter laboratory conditions.)

MCA2.1.8 Unless otherwise agreed by the Single Buyer and User, the following test and inspection intervals shall be observed by the Single Buyer.

Maximum allowable period between tests

Metering Installation Equipment	Metering Installation Type	
	Type 1	**Type 2**
CT	10 years	10 years
VT	10 years	10 years
Burden Tests	Whenever Meters are tested or when Modifications are made	
CT Connected Meter (Electronic Type)	5 years	5 years

Maximum allowable period between inspections

Inspection of Metering Installation Equipment	Metering Installation Type	
	Type 1	**Type 2**
Maximum allowable period between inspections	2.5 years	2.5 years

MCA2.2 Technical Requirements

MCA2.2.1 In commissioning, testing and inspecting all new, modified and replacement Metering Installations the User shall ensure that the following are confirmed, recorded and notified to the Single Buyer in accordance with the relevant Agreement:

(a) current and voltage transformers are tested by primary injection and CT ratio and polarity for selected tap and VT ratio and phasing for each winding;

(b) details of installed current and voltage transformers including serial numbers, ratings and accuracy classes;

(c) burdens of current and voltage transformers for verification;

(d) Metering Installation details for the Metering Register;

(e) correct operation of Meter test terminal blocks;

(f) correct cabling and wiring;

(g) correct Meter operation for each phase current operation;

(h) correct storage (storage frequency and retention period) at data registers on-site;

(i) Meter to RTU connections and channel allocations and local and remote interrogation facilities;

(j) correct communication with the Automatic Data Collection System;

(k) labelling, start readings, synchronization of timing, Metering equipment alarms and all other relevant information as requested by the Single Buyer, Grid Owner or GSO; and

(l) Meter accuracy field tests as applicable.

MCA2.2.2 A typical Meter inspection shall include the following but not limited to the following:

(a) checking the Meter seals;

(b) comparison of pulse counts;

(c) comparison of the direct Meter readings;

(d) verification of Meter accuracy, parameters and physical connections; and *(e)* current and voltage transformer ratios by comparison.

MCA2.2.3 The labelling of the Metering Installation shall be in accordance with the following convention, which establishes the relationships between Import and Export of Active Energy and Reactive Energy by means of a power factor:

Convention for Import and Export of Active Energy and Reactive Energy

Active Energy Flow	Power Factor	Reactive Energy Flow
Import	Lagging	Import
Import	Leading	Export
Import	Unity	Zero
Export	Lagging	Export
Export	Leading	Import
Export	Unity	Zero

For the avoidance of doubt, Export in relation to the Grid System is the flow of Active Energy as viewed by a Generator is away from the Generator.

< Metering Code - End of Appendix 2>

Metering Code Appendix 3 – Metering Register

MCA3.1 General

MCA3.1.1 The Metering Register forms part of the Metering Database and holds static Metering information not subject to frequent change associated with the Metering Installations as defined in this Metering Code that determine the validity and accuracy of the Metering Data.

MCA3.1.2 The purpose of the Metering Register is to facilitate:

(a) the registration of each Metering Installation at the Connection Points;

(b) verification of the compliance of each Metering installation with the Metering Code; and

(c) auditable control of changes and Modifications to Metering Installations.

MCA3.1.3 The data held in the Metering Register is confidential at all times and disclosure shall be treated accordingly.

MCA3.2 Metering Register Information

MCA3.2.1 Metering information held in the Metering Register shall include, but is not limited to the following as agreed between the Single Buyer and the User in the Connection Agreement.

MCA3.2.2 Connection Point and Metering Point reference details, including:

(a) agreed locations and reference details;

(b) loss compensation calculation details; and

(c) site identification details and User details.

MCA3.2.3 Characteristic details of the Metering equipment within the Metering Installation:

(a) Metering Installation name, recorder ID and location identifier;

(b) serial numbers and technical details of all CTs, VTs, Meters, Data Loggers, recorders, file formats and modem details;

(c) test results for the CTs, VTs, Meters including the compensation factors applied, calibration tables; and

(d) reference laboratory test certificates for all relevant Metering Installation equipment.

MCA3.2.4 Data validation and substitution processes agreed between the Single Buyer and User or between Associated Users, including:

(a) algorithm and data comparison process;

(b) alarm processing;

(c) Check Metering compensation; and

(d) alternate data sources.

MCA3.2.5 Data processing details prior to Settlement including algorithms for, half hourly generation “sent out” and User half hourly load calculations.

MCA3.2.6 Data communication and local and remote access details, including:

(a) telephone number for data access;

(b) technical details of communication equipment including the type and serial numbers;

(c) communicational protocol details;

(d) data conversion details;

(e) user identifications and access details; and

(f) passwords.

MCA3.2.7 The Single Buyer shall prepare appropriate formats for collection of data for the Metering Register

MCA3.3 Metering Point Documentation Requirements

MCA3.2.8 There shall be appropriate documentation prepared in a format in accordance with the requirements of the Single Buyer for each Metering Point showing the electrical and physical location details of the Metering Installation and its components for the purpose of ensuring safety in testing and inspections and providing the appropriate details to staff attending the site. This document shall be kept by the User and the Single Buyer.

MCA3.2.9 The documentation shall include, but is not limited to the following:

(a) a Meter map containing any summation arrangements and channel identifications including the sign of the summations applicable;

(b) a unique identifier for the Metering Database and cross references to the Metering Installation;

(c) list of measured quantities;

(d) details and designation of the Metering Point;

(e) site specific adjustments, calibration and error correction factors including relevant power flow calculations for validation; and

(f) redundancy and back-up for Metering data with list of contacts for provision of back-up data and resolution of gaps in data.

< Metering Code - End of Appendix 3>

<End of the Metering Code>

Cybersecurity Code (CSC)

CSC.1 Preamble

CSC.1.1 The Grid Code is a code developed and issued by the Commission. The Grid Code is composed by a Main Code, containing the main provisions structuring the purpose, the scope, the governance and some general requirements, and by additional codes, containing the specific technical rules for different subjects related to the operation of the Grid system.

CSC.1.2 According to section 50A of the Electricity Supply 1990 [*Act 447*], the Commission may develop and issue such additional codes as it deems fit and expedient or the Minister may direct from time to time, as the case may be.

CSC.2 Amendment

CSC.2.1 The Commission may at any time amend, modify, vary or revoke this Code or any part thereof.

CSC.3 Introduction, Objectives and Scope

CSC.3.1 The provisions of sections MCSC.1, MCSC.2 and MCSC.3 of the Main Code shall apply to this Cybersecurity Code.

CSC.4 General requirements

CSC.4.1 The Grid Owner, the GSO, the Single Buyer and the Users shall apply the international reference standards in the field of information systems and Cybersecurity. The following standards are recommended for application:

(a) ISO/IEC 27001: Information security management system;

(b) ISO/IEC 27019: Information technology - Security techniques - Information security controls for the energy utility industry;

(c) IEC 62443: Industrial communication networks - Network and system security.

CSC.4.2 The GSO, Single Buyer, Grid Owner and all Users shall each establish an individual Cybersecurity Policy. The Cybersecurity Policy is a set of practices and procedures designed to protect the electric utilities and the Grid System from probable Cyber Threats that could have major impact to the reliability and security of grid system operations. The Cybersecurity Policy may be in accordance with the best practices defined in the applicable standards stated in CSC.4.1.

CSC.4.3 Cybersecurity Policy shall address the following elements:

(a) Policy management: this shall address the purpose, scope, applicability, roles and responsibilities; implementation and enforcement procedures; exceptions, and policy reviews; approvals, and change management;

(b) Critical Asset management: methodology for identifying critical cyber Assets; inventory and classification of cyber Assets, information protection and data privacy; cyber Vulnerability Assessment;

(c) Electronic Security Perimeter (ESP): Critical Assets within the perimeter; cyber Vulnerability Assessment; access control/monitoring and logging, configuration, maintenance, and testing; documentation maintenance to support compliance;

(d) Physical security perimeters: fences, walls, gates and other barriers that prevent unauthorized access to the critical cyber Assets;

(e) Personnel and training: personnel risk assessment, security awareness program, and Cybersecurity training.

CSC.4.4 Cybersecurity Policy shall leverage advanced Cybersecurity technologies and relevant processes to mitigate the Cybersecurity risks and Vulnerabilities.

CSC.4.5 Cybersecurity Policy documents, and any amendments to them, shall be forwarded by the Grid Owner, the GSO, the Single Buyer and the Users to the GCC Secretariat.

CSC.5 Cybersecurity governance and management

CSC.5.1 The GCC may—

(a) regularly review this code to ensure that the applicable provisions follow the Malaysian laws and the international best practices in the electricity sector;

(b) propose amendments to the Grid Code to strengthen the Cybersecurity of the Grid System;

(c) establish a Grid Code sub-committee to deal with matters related to the Cybersecurity of the Grid System, in accordance with Article GC5.6 of the General Conditions of the Grid Code;

(d) conduct Cybersecurity audits when Cybersecurity Incidents affect the grid.

CSC.5.2 It is the responsibility of the Grid Owner, the GSO, the Single Buyer and the Users to appoint an employee acting as an Information Security Officer (ISO).

CSC.6 Cyber Threats identification

CSC.6.1 The Grid Owner, the GSO, the Single Buyer and the Users shall identify Critical Assets and make maximum possible efforts to protect them from potential Cyber Attacks, to support the reliable and secure operation of the Grid System.

CSC.6.2 The Grid Owner, the GSO, the Single Buyer and the Users shall adopt a Cybersecurity risk management approach that applies to the following phases:

(a) Context establishment;

(b) Vulnerability Assessment;

(c) Risk treatment; and

(d) Risk acceptance.

CSC.6.3 The methodology and results of this Cyber Threats identification process should be described in the Cybersecurity Policy issued by the Grid Owner, the GSO, the Single Buyer and the Users.

CSC.7 Detection and handling of Cybersecurity Incidents

CSC.7.1 The Grid Owner, the GSO, the Single Buyer and the Users shall implement effective processes to identify, classify and respond to Cybersecurity Incidents that will or may affect the Grid System, in order to minimize the impact of a Cybersecurity incident or Cyber Attack and to react quickly.

CSC.7.2 In the event of any actual or suspected unauthorized access or compromise to any communication and information system links between the Users and the GSO, the Users shall —

(a) notify the GSO and the Commission;

(b) take necessary actions to remedy the event as soon as possible; and

(c) comply with the instructions of the GSO in respect to any additional or different security measures as may be required to respond to such Cybersecurity Threats.

CSC.7.3 The GSO and the Users shall —

(a) Trigger the Cybersecurity incident management procedures;

(b) Communicate Cybersecurity incidents to the Commission and the GCC;

(c) Provide a post-mortem and remediation action of the Cybersecurity Incidents to GCC.

CSC.8 Cybersecurity training

CSC.8.1 The Grid Owner, the GSO, the Single Buyer and the Users shall be responsible for preparation, consultation and implementation of regular Cybersecurity training or awareness program to the respective personnel who has been authorized to access any of the Critical Systems used for power system control.

CSC.8.2 The Grid Owner, the GSO, the Single Buyer and the Users shall review annually their Cybersecurity training or awareness program and shall update it wherever necessary. Annual reviews shall evaluate the effectiveness of the training sessions held.

CSC.9 Cybersecurity Procurement Requirements

CSC.9.1 The Grid Owner, the GSO, the Single Buyer and the Users shall make Cybersecurity a key consideration in every phase of procurement and shall define Cybersecurity Procurement Requirements for their ICT equipment by —

(a) analysing the possible Cyber Threats; and

(b) selecting relevant measures to mitigate them.

These measures should take into account what is currently feasible in the market.

CSC.10 Specific Technical requirements for Cybersecurity

CSC.10.1 The Grid Owner, the GSO, the Single Buyer and the Users shall, at their own cost and expense, install or procure the installation of all reasonable Cybersecurity protection, including the anti-virus and anti-malware, firewalls or functionality equivalent technology and authentication controls for the protection against unauthorized access, misuse, damage, destruction and other Cybersecurity Threats.

CSC.10.2 The Grid Owner, the GSO, the Single Buyer and the Users shall plan, design and execute communication infrastructure and architecture as per the relevant international Cybersecurity standard and the directives for CNII by the National Security Council, issued from time to time.

CSC.10.3 The existing communication or OT network shall be maintained properly by the Grid Owner, the GSO, the Single Buyer and the Users to ensure uninterrupted continuous operation.

CSC.11 Cybersecurity audits

CSC.11.1 The Grid Owner, the GSO, the Single Buyer and the Users shall routinely conduct —

(a) cyber vulnerability test;

(b) mock drills;

(c) cyber audit; and

(d) other measures as per the incident management procedures.

CSC.11.2 The Grid Owner, the GSO, the Single Buyer and the Users shall conduct regular Cybersecurity audit by appointing third party auditor which has been authorized and approved by GCC.

<End of the Cybersecurity Code>

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