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Our Ref: PLS 8/1/GSO/lsk

September 2024

Engineering Circular No. 11/2024

<u>Guidelines and Requirements for</u> <u>Large-Scale Solar Connection to Sarawak Grid System</u>

The SESCO Technical Approving Committee (STAC) in its Meeting No. 5/2024 has approved the circular on the Guidelines and Requirements for Large-Scale Solar Connection to Sarawak Grid System.

The objectives of this circular are as follows:

a. To establish a consistent and formal procedure for development of large-scale solar (LSS) power plants and to provide guidance to prospective Developers seeking connection to the Sarawak Grid System.

b. To set performance standard for the evaluation of new or existing Plant's dynamic behaviour.

c. To assess and determine the operational ranges and limits of the LSS, ascertain its interaction dynamics with Grid System and other Solar PV System(s) when subjected to disturbances, and to uncover hidden system performance, stability and security issues.

d. To verify that the Plant's performance conforms to the required technical and operational criteria as defined in this standard, to ensure reliable operation, compliance with planning and operation criteria and Prudent Utility Practice as well as meeting legal requirements.

e. To ensure timely submission and updating of accurately validated steady state and dynamic models (through simulation, compliance testing, post-commissioning monitoring) for planning and operational studies.

This circular shall be implemented with immediate effect.

Lau Kim Swee
Chief Executive Officer
SESCO

Encl.

Grid System

Standard Operating Procedures (SOP)

Guidelines and Requirements for Large-Scale Solar Connection to Sarawak Grid System

1st Edition September 2024

This SOP is prepared by Grid System Operator Department and maintained by Asset Management Department.

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Last updated: September 2024

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AMENDMENT HISTORY

Title	**Guidelines and Requirements for LSS Connection to Sarawak Grid System**				
Circulation	SEB Group			**Issued by**	GSA Division, GSO
Revision	**Date**	**Prepared**	**Reviewed**	**Agreed**	**Amendments/ Remarks**
Preliminary A	19/09/19	LSK	GSA		Preliminary
Preliminary B	19/04/23	LSK	GSO		First Draft for comments
Draft	28/07/23	GSA	SB, TNSP	SB, TNSP	Final Draft for STAC submission
Draft	07/09/23	GSA	STAC	STAC	Final pending MUT endorsement
Final	27/02/24	GSA	MUT	MUT	Presented to MUT
Final	19/03/24	GSO	Public	Public	Presented to Industry, Unimas, MPIA, ACEM
Final	03/07/24	GSO	EPU	EPU	Presented to EPU
Final	10/09/24	GSO	MUT	MUT	Endorsed by MUT
Edition 1.0	18/09/24	Document approved by STAC to be issued as Engineering Circular No. 11/2024			

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ABBREVIATIONS AND DEFINITIONS

In this document, the following words and expressions, including abbreviations shall, unless the subject matter or content otherwise requires or is inconsistent therewith, bear the following meanings:

Active Power	Instantaneous power derived from in-phase voltage and current and is measured in watts (W) or multiples thereof (MW).
Apparatus	All User's equipment in which electrical conductors are used, supported or which they form a part.
Availability	The MW Capacity of a Solar PV System made available to the GSO across a specified time period by a Solar Power Producer (SPP) in an Availability Notice.
Connection Agreement (CA)	An agreement between a User and a TNSP by which the User is connected to the Grid System at a Connection Point.
Connection Facilities	Means the Plant and Apparatus between the Plant and the SESCO Substation, and includes: (a) the switching/isolation equipment located at both substations; (b) the transmission line and/or underground cable; (c) the metering installations and control/protection equipment; (d) the SESCO data acquisition and communication equipment; and (e) the monitoring equipment (PMU, Disturbance Recorder, PQ etc.).
Connection Point	The site, or in the case of a schematic diagram the node point, on the Grid System at which a User connects their User System to the Grid System, under the terms of their Connection Agreement (CA). This is where the TNSP's Apparatus connects to the User's Apparatus and consequently results in an asset ownership interface.
Custody Transfer Point	The site on a SESCO Network, or a User's Network, where supply of electrical energy by one User to another User is metered. The Custody Transfer Point does not by itself constitute a Connection Point. It is a metering point, where the custody of the commodity (electricity) has been transferred from one party to another.
Developer	For the purpose of this document, it could mean the SPP, or any parties appointed by SPP to plan and develop a large-scale solar (LSS) Plant who requested the connection of the Plant to the Transmission Network.
Frequency Sensitive Mode	The operation of a Solar PV System in a frequency sensitive mode that will result in Active Power output changing in response to changes in Grid System frequency.
Capability Limits	A capability chart, registered with the Single Buyer and the GSO, which shows the MW and MVAr capability limits within which a Solar PV System will be expected to operate under steady state conditions.

Grid Code	The Electricity (State Grid Code) Rules, 2003, which lays down the statutory rules to regulate the generation, transmission and distribution of electricity within the State of Sarawak.
Grid System	The interconnected power system within the state of Sarawak consisting of both the Transmission Networks and Distribution Networks and the power stations connected to these Networks.
Grid System Operator (GSO)	The department in SESCO responsible for the overall coordination of the operation, maintenance and development of the Grid System amongst all the Users. The GSO is also responsible for generation Scheduling and Dispatch and monitoring and control of the Grid System to ensure that the Grid System is operated reliably, securely, safely and economically.
High Frequency Response	Formed part of Primary Reserve, an automatic reduction in Active Power output in response to an increase in Grid System frequency above the target frequency. The decrease shall be fully achieved within 5 seconds from the start of frequency increase and shall be sustained at no lesser reduction thereafter.
Maximum Continuous Rating (MCR)	The maximum loading of the Solar PV System concerned, as registered with the Single Buyer, under an agreement, at which the Solar PV System can operate continuously without any undue degradation of operational performance, in accordance with Prudent Utility Practice. For the avoidance of doubt, for some cases MCR could be lower than the temporary, short-term rating and nameplate Rated MW subject to availability of the primary energy source (solar irradiance).
Minimum Generation (PMIN)	The minimum stable output (in whole MW) that a Solar PV System has registered with the Single Buyer.
Operational Diagram	A schematic representation of all User and SESCO Plant and Apparatus and circuits at the Connection Point incorporating its numbering, nomenclature and labelling.
Operation Manual (OM)	A document agreed and maintained between the GSO and the SPP to ensure effective coordination and communication with regard to the operation of the supply system. OM could also be included as part of CA.
Plant	The SPP's Solar PV Systems together with its associated auxiliary equipment, stores and stocks, buildings and property at or adjacent to the generating site and including fixed or movable equipment used in the generation of electricity and Apparatus belonging to the SPP and required for the connection of these Solar PV Systems to the Grid System. For context, this includes the grouping of one or more Solar PV System(s) and possibly supplemental device(s) operated by a common facility-level controller along with a collector system.
Primary Reserve	An automatic response by a Solar PV System to a fall or rise in Grid System frequency which require changes in the Solar PV System's output, to restore the frequency to within target limits. Such response should be fully available within 5 seconds and sustainable for a further 25 seconds.

Rated MW	The "rating-plate: MW output" of a Solar PV System, being the nominal rating for the MW output of a Solar PV System. For the purpose of this document, this being the aggregate Active Power nameplate rating or installed capacity of the Solar PV Systems.
Reactive Power	Instantaneous power derived from the product of voltage and current and the sine of the voltage-current phase angle which is measured in vars (VAr) or multiples thereof (MVAr).
SESCO	SESCO means the Syarikat SESCO Berhad, the successor company for the Sarawak Electricity Supply Corporation established under the Sarawak Electricity Supply Corporation Ordinance, 1962.
Single Buyer	The agency appointed by the Regulator responsible for: (a) monitoring the scheduling, dispatch and operational planning by the GSO to ensure the equitable treatment of all Power Producers and to meet adequacy of Demand; (b) procuring new generation Capacity; and (c) ensuring that all new Power Purchase Agreements (PPAs) between the relevant parties meet the requirements of the Grid Code and Licence requirements. Refers to Sarawak Energy Berhad in Electricity (Amendment) Ordinance and represented by Single Buyer under Strategy & Corporate Department.
Solar PV System	A system of converting sunlight directly into electricity which includes solar PV cells, PV modules, inverter, the associated switching, protection and control devices, cables and other related Apparatus and equipment.
Solar Power Producer (SPP)	Any entity which has a generation Licence, including SESCO, IPPs and Self-generators which owns or operates a large-scale solar (LSS) Plant, with capacity as approved by the Single Buyer, which connects through its User System and on to the Grid System.
Transmission Network	The transmission networks namely transmission lines, substations and other associated Plant and/or Apparatus operating at 132 kV and above in the State of Sarawak.
Transmission Network Service Provider (TNSP)	That entity holding a transmission Licence responsible for the operation and maintenance of a Transmission Network and its associated Plant and Apparatus for the purpose of providing transmission services, including access to Users of the Grid System. In context, Transmission System Planning & Development under TNSP/ Transmission Department shall act as the TNSP Network Planner.
User	Any person other than the GSO and the Single Buyer, making use of the Grid System, as more particularly identified in each section of the Grid Code.

REFERENCE DOCUMENTS

[1] Electricity Rules, 1999, January 2000.

[2] The Electricity (State Grid Code) Rules, 2003, January 2004.

[3] Electricity (Amendment) Ordinance, 2023.

[4] Energy Commission, "Guidelines on Large Scale Solar Photovoltaic Plant for Connection to Electricity Networks", GP/ST/No.1/2016(pin.2020), 22 May 2020.

[5] Engineering Circular No. 04/2009 "Guidelines for Request for Connection to the Grid System (RCGS)".

[6] Engineering Circular No. 16/2021 "Guidelines and Requirements for System Integration Study".

[7] Engineering Circular No. 11/2022 "Grid System Operation Procedures & Guidelines".

[8] Engineering Circular No. 11/2023 "Grid System Power Quality Meter Requirements".

[9] "Transmission System Operation Standard (TSOS)" issued by SESCO.

[10] CIGRE JWG C4/C6.35/CIRED, "Modelling of Inverter-Based Generation for Power System Dynamic Studies," TB727, May. 2018.

[11] IEEE 1547 - Standard for Interconnecting Distributed Resources with Electric Power Systems.

[12] IEEE 2800-2022 - IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems.

[13] IEC TR 63043:2020 Renewable energy power forecasting technology.

[14] IEC TS 63102:2021 Grid code compliance assessment methods for grid connection of wind and PV power plants.

APPLICABILITY

a. This document was prepared by **GSO** in consultation with **Single Buyer** and **TNSP**. It aims to provide guidance to **Solar Power Producer (SPP)** in fulfilling the relevant Schedules of the **Grid Code** to promote the security and reliability of the electricity generation in the state of Sarawak. This document must not be used as a substitute to the **Grid Code**, and if there is any conflict between this document and the **Grid Code**, then the **Grid Code** shall take precedence.

b. This document only sets out the procedures and requirements arising from prospective large-scale solar (LSS) plants **Developers** seeking connection to the Sarawak **Grid System**. It does not include the mandatory obligations for approval, development, commercial and power purchase of LSS plants set out by **Single Buyer**. The content of the guidelines was prepared based on Prudent Utility Practice and international standards.

c. This document was prepared for guidance and informational purpose only. It does not contain comprehensive information needed for the planning and design of the facilities needed for the **Plant**. The guidelines are not intended to cover all required authorisations, permits and/or licenses which the **SPP** is required to obtain from the relevant bodies and/or authorities.

d. If **SPP** finds that it is, or will be, unable to comply with any requirements stated in this document, then it shall, without delay, report such non-compliance to **Single Buyer** and **SESCO** and make such reasonable efforts as are required to remedy such non-compliance as soon as reasonably practicable.

e. The content of this document may not be the **SESCO's** final or complete view on any particular subject, and all provisions stated herein are subject to change. This document will be updated from time to time. **SESCO** shall make reasonable efforts as are required to remedy whole or part of document to comply with any provision of **Grid Code** or for continual improvement on the document's content.

1. INTRODUCTION

The global increase in penetration levels of inverter-based resources (IBRs) is expected to significantly change the dynamic performance of the power grid. As the penetration levels of IBRs increase and the technology of IBRs evolves, specifications and standards are needed to address the performance requirements of IBRs.

Under National Energy Policy (NEP) 2022-2040 Action Plan A7, the initiatives to enhance and unlock potential of indigenous solar resources include long-term pipeline of large-scale solar (LSS) projects and high potential floating solar with synergies between hydro and solar resources.

One of the key outcomes in Sarawak Post Covid-19 Development Strategy (PCDS) 2030 is to maintain at least 60% Renewable Energy capacity mix by 2030. Besides incentivise Net Energy Metering (NEM) programs, PCDS also introduced catalytic initiatives to promote solar projects and increase renewable energy generation capacity.

Generally, the connection requirement in the Sarawak **Grid Code** to ensure system stability is critical and needs to be abided by all **Users** including the prospective solar connection.

The existing requirements on criteria and standards for connection to **Grid System** are applicable as specified in the following documents, whichever pertinent:

i. The Electricity Rules, 2003 (State Grid Code)
ii. Engineering Circular No. 04/2009 "Guidelines for Request for Connection to the Grid System (RCGS)"
iii. Engineering Circular No. 16/2021 "Guidelines and Requirements for System Integration Study"
iv. Engineering Circular No. 11/2022 "Grid System Operation Procedures & Guidelines"
v. Engineering Circular No. 11/2023 "Grid System Power Quality Meter Requirements"
vi. "Transmission System Operation Standard (TSOS)" issued by SESCO

The following standards shall be of equal relevance as additional information:

i. CIGRE JWG C4/C6.35/CIRED, "Modelling of Inverter-Based Generation for Power System Dynamic Studies," TB727, May. 2018
ii. IEEE 1547 - Standard for Interconnecting Distributed Resources with Electric Power Systems
iii. IEEE 2800-2022 - IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems

2. OBJECTIVES

This guideline is developed with the following objectives:

a. Standard

To fulfil Planning Code (PC) of the **Grid Code**, i.e., to establish a consistent and formal procedures for development of large-scale solar (LSS) power plants and to provide guidance to prospective **SPP** and **Developers** seeking connection to the Sarawak **Grid System**; and to set performance standard of **Solar PV System(s)** for Network Planners, **GSO**, prospective and existing **User(s)** to evaluate new or existing **Plant's** dynamic behaviour.

b. Performance

In line with Connection Conditions (CC) of the **Grid Code**, to assess and determine the operational ranges and capability limits of the **Plant**, ascertain the impact of this new connection and interactions with **Grid System** and other **Solar PV System(s)**, when subjected to disturbances, and to uncover hidden system performance, stability and security issues.

c. Compliance

To comply with Operating Code (OC) of the **Grid Code**, i.e., to verify that the **Plant's** performance conforms to the required technical and operational criteria as defined in this standard so that it may operate reliably in the **Grid System** according to planning and operation criteria, Prudent Utility Practice and meeting legal requirements.

d. Validation

To ensure timely submission and updating of accurately validated steady state and dynamic models (via simulation, compliance testing and post-commissioning monitoring) for planning and operational studies.

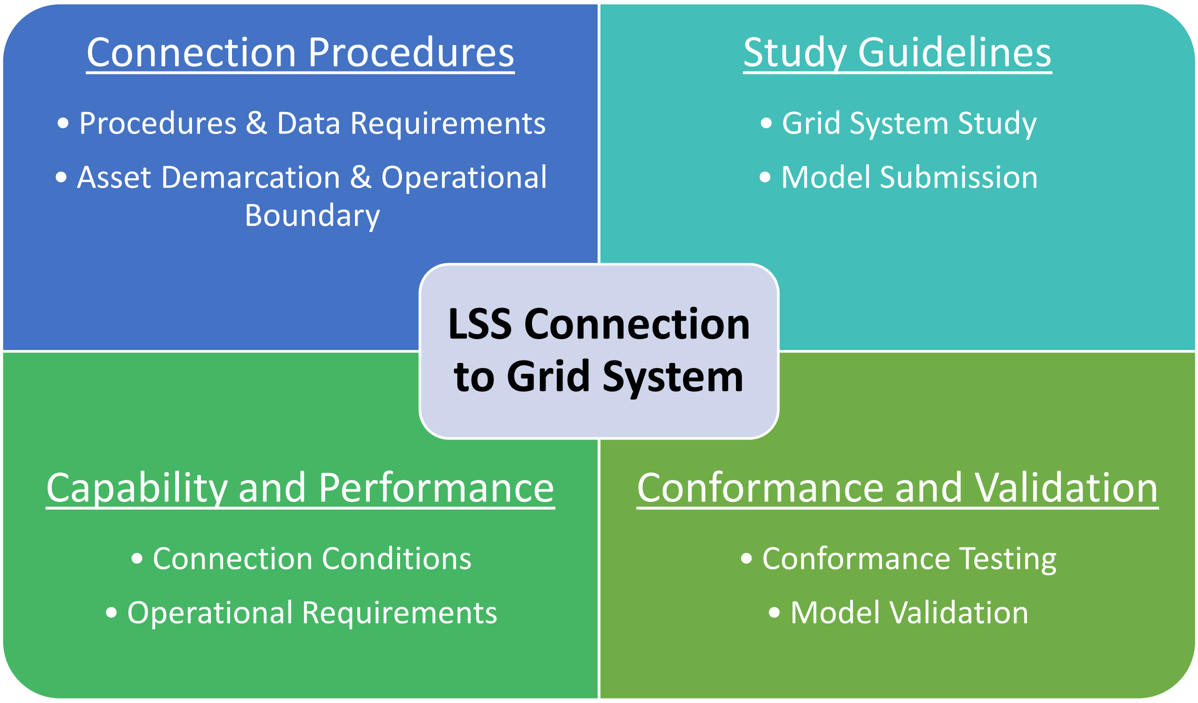
3. SCOPE

This guide shall apply to any **User** utilising renewable energy sources (solar PV) for power generation and seeking connection to the **Transmission Network** with total capacity at ONE **Connection Point** of 30MW_{ac} and above.

The maximum capacity that is allowed to be connected to the **Transmission Network** via one **Connection Point** shall be subject to consent from **Single Buyer**. **Single Buyer** and/or **User** should avoid the use of **Solar PV Systems** that are too large for the **Grid System**, such that the provision of excessive Spinning Reserve is required (PC5).

This document does NOT apply to Distributed Generation (DG) or Distributed Energy Resources (DER) and Net Energy Metering (NEM) or Self-Consumption (SELCO) schemes, which comprises generation schemes connected to Distribution Network operating at high voltage from 11kV up to 33kV.

The scope of this document comprises four (4) main sections:



4. Connection Procedures

4.1 Procedures and Data Requirements

Primarily, the Planning Code (PC) shall be referred for the procedures involved for new **Users** intending to connect on to the **Grid System** and the data to be provided to the **Transmission Network Service Provider (TNSP) Network Planner**.

After the development is approved by the **Single Buyer**, the subsequent process and indicative timeline for connection to the **Grid System** is described in the *Flowchart on the Process of Grid System Connection for LSS* in Appendix A.

In accordance with the **Grid Code**, the **Developer** is to submit duly filled *Application Form for Connection to the Grid System* to the **TNSP Network Planner**, complete with sufficient/ relevant Planning Data of the **Plant** (see Appendix B). The latest *Application Form for Connection to the Grid System* can be obtained from the **TNSP Network Planner**.

Prior to the physical Grid connection, the procedures outlined in the Engineering Circular No. 4/2009 "Guidelines for Request for Connection to the Grid System (RCGS)" and Engineering Circular No. 11/2022 "Grid System Operation Procedures & Guidelines" shall be fulfilled.

The **Developer** is required to furnish to the **TNSP Network Planner** the following information together with the submission of formal application:

i. Description of the proposed development and expected completion date.
ii. Standard Planning Data (PC A1) and Detailed Planning Data (PC A2) (see Appendix B).
iii. Original equipment manufacturer (OEM) data (PV array, inverter, PPC, etc.).

Largely, the Connection Conditions (CC) in **Grid Code** specify the minimum technical, design and certain operational criteria which must be complied with by the **Solar Power Producer (SPP)** connected to or seeking connection to the **Grid System**. They also set out the procedures by which the **TNSP** will seek to ensure compliance with these criteria as a requirement for the granting of approval for the connection (CC6).

TNSP will not grant approval to connect to the **Transmission Network** until it is satisfied that the criteria laid down by the CC and other requirements have been met.

The capacity of the connection shall be appropriately designed to cater for full power export to the **Grid System**. The scheme shall allow for switching of the **Connection Facilities** to ensure the reliability and security of the **Grid System**.

4.2 Asset Demarcation and Operational Boundary

Single Buyer and **TNSP Network Planner** identify renewable energy zones with suitable hosting capacities, where clusters of large-scale renewable energy projects can be developed using economies of scale. To facilitate potential **SPP** and **Developers**, certain locations have been identified as possible regional nodes for grid connection. In general, space provisions or spare bays at existing substations are planned for future development. For transmission connected **Plants**, the connection scheme to existing substation is described in the following.

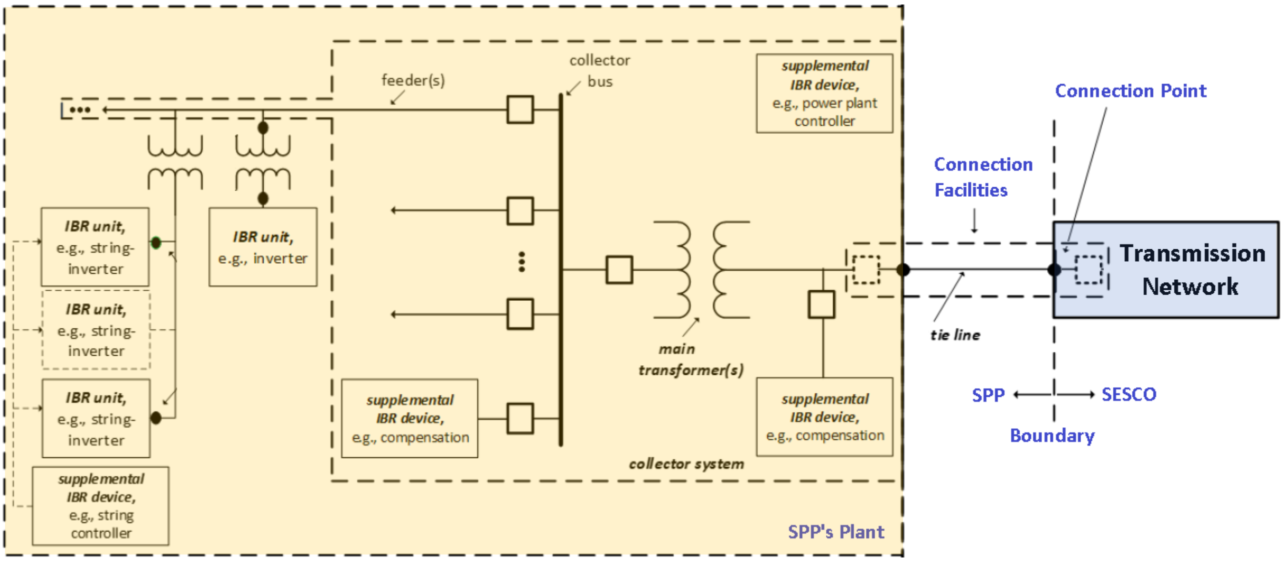


Figure 4.1 Example illustration of scope and asset demarcation (adapted from IEEE 2800)

The **Connection Point** shall be used to demarcate the asset ownership boundary between **SESCO** and **SPP**. The **Custody Transfer Point** for metering shall be as close as practicable to the **Connection Point**.

New bay(s) extension works at existing substation shall be built and owned by **SESCO** at the cost of **SPP**. Regardless of the tie line length, the **Developer** shall build, own, operate and maintain the tie line be it within the **Plant** boundaries, in public area or areas owned by third parties.

The **Connection Point** shall depend on the medium of connection as well as the type of termination involved. The connection method to the **Grid System** can be either through overhead transmission line or underground cable. The **Connection Point** will be at the cable sealing end at the substation (in the case of underground cable connection) and at the line dropper (in the case of overhead transmission line connection).

All costs associated with the connection of the **Plant** shall be borne by the **SPP**. Materials and standard installation works required for **Connection Facilities** at **SESCO's** substation shall be chargeable to the **SPP** and the costs shall be based on the actual incurred basis.

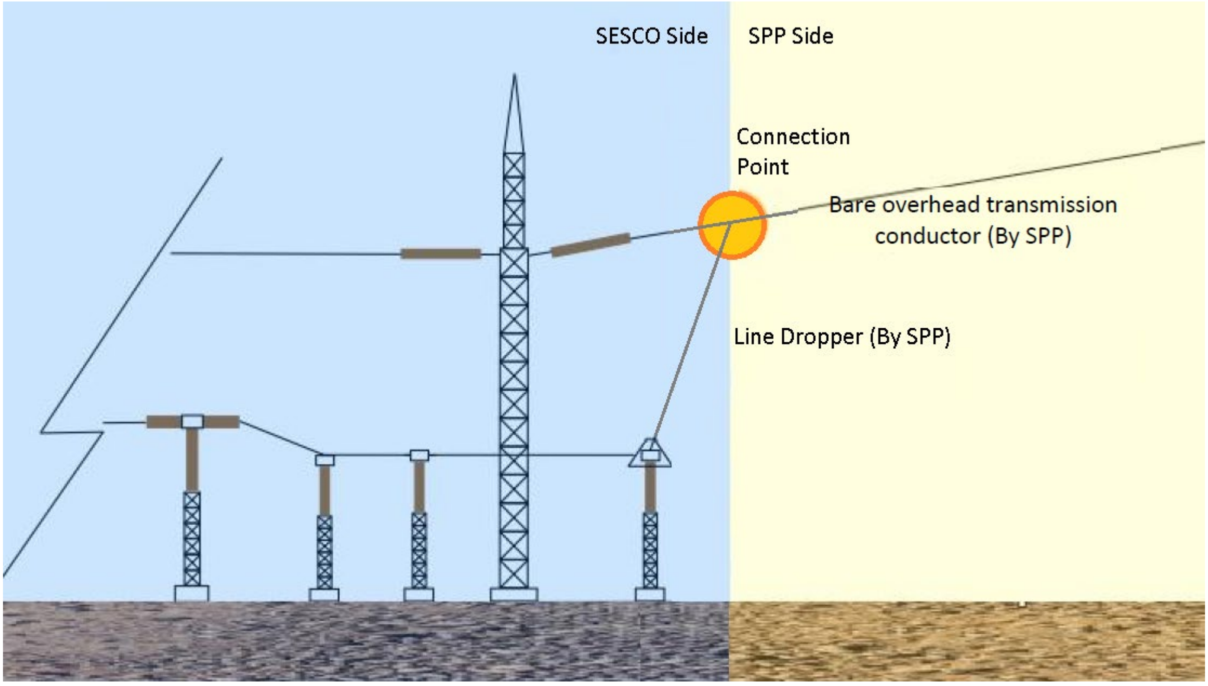


Figure 4.2 Connection Point at the connector of the down-dropper on the overhead line (OHL)

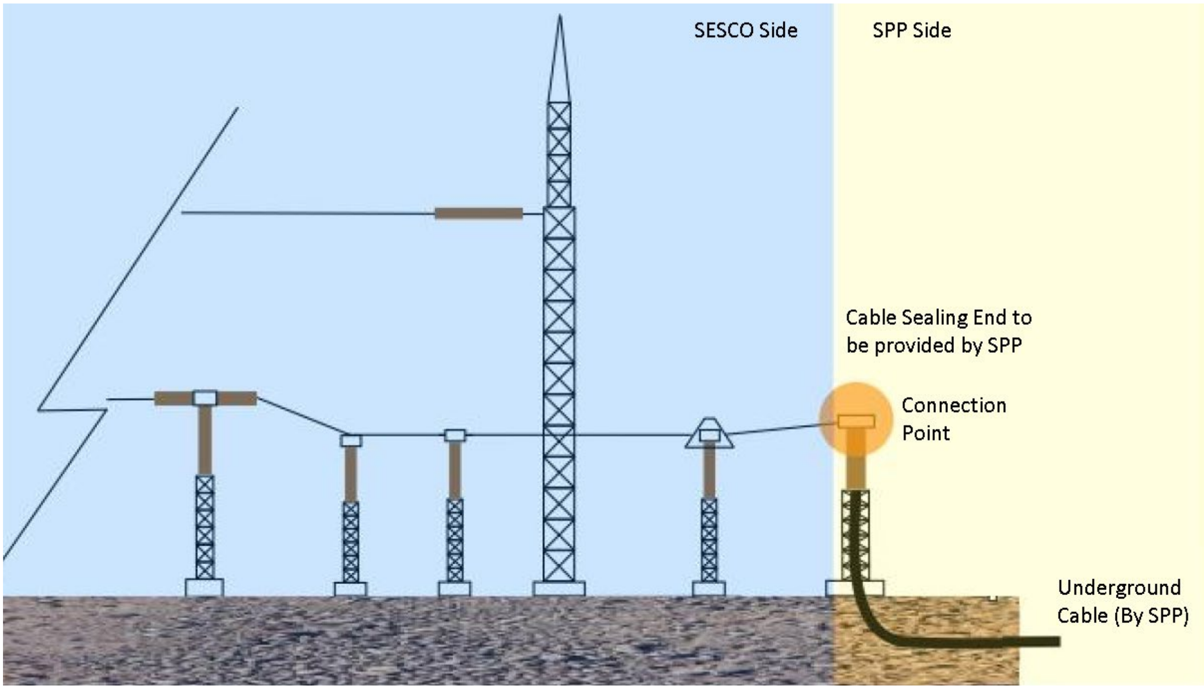


Figure 4.3 Connection Point at the connector of the Cable Sealing End on underground (U/G) cable

The **Developer** shall, at its own cost and expense, be fully responsible for the following scope:

i. Land acquisition and obtaining necessary right-of-way (ROW) and permits from relevant local authorities, for the development of the **Plant**, **Connection Facilities**, and tie line up to the **Connection Point**.
ii. Inspect, examine and verify the accuracy and completeness of any and all data as to the conditions of the site and its surroundings and the nature of the climate and geology.

iii. Design of appropriately rated **Connection Facilities** equipment, compatible with ratings at **SESCO** side (**Connection Facilities** shall have the capability to withstand voltage and current surges in accordance with the ratings as specified by **SESCO**).
iv. Design, procurement, construction, commissioning, testing and completion of the **Plant** and **Connection Facilities** between the **Plant** and **Connection Point** (including tie line).
v. Installation of equipment, including visible-break isolation device, synchronising, power cables and fibre optics, which comply with existing **SESCO** standards/ specifications.
vi. Coordination of protection schemes and interlocking schemes.
vii. Monitoring equipment: PMU, Disturbance Recorder, PQ meter (see Section 7.3).
viii. Installation of Meteorological Measuring Facilities (MMF) at appropriate locations within the site: at least one (1) set of pyranometer and one (1) set of full weather station for every $20MW_p$ in accordance with IEC 61724.
ix. SCADA requirements via telemetry facility using specified protocol (real-time data from the **Plant** including data from the pyranometers and weather station).
x. Initiate and accomplish Grid System Study i.e. Stage 1 Planning & Development Study and Stage 2 System Impact Study (see Section 5), together with the submission of models validated through System Tests.
xi. Undertaking to comply with the capability and performance requirements (see Section 6) and any other connection requirements as reasonably specified by **SESCO**, with conformance verified during Grid System Study, commissioning tests and post-commissioning monitoring.
xii. Attain relevant competency certifications from the relevant bodies and/or authorities for design, installation and testing of the **Plant**.
xiii. Other requirements as stated in the Grid System Study and **Connection Agreement (CA)**.

Both **SESCO** and **Developer** shall exercise reasonable endeavours to coordinate the installation of their respective protection, control, communication systems, telemetering and SCADA facilities, according to the relevant provisions of technical standards determined by **SESCO** from time to time.

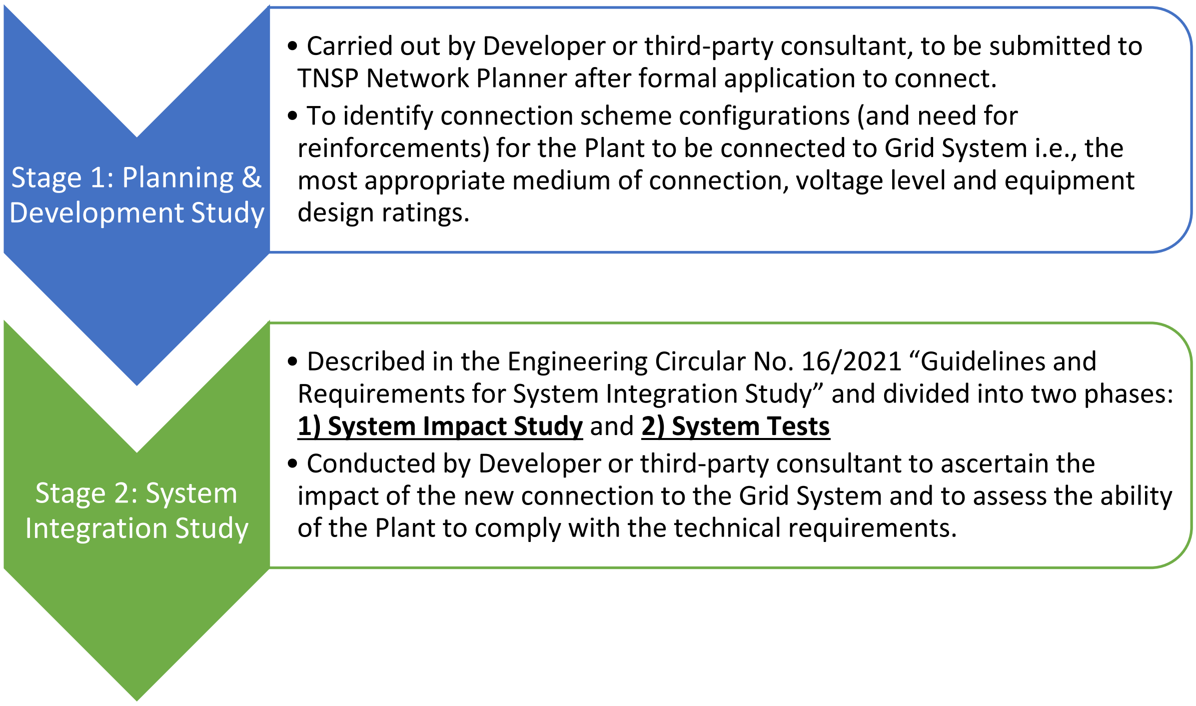
GSO and **SPP** shall jointly prepare an **Operation Manual (OM)** (could also form part of the **CA**) which must be completed and signed off by both parties prior to energisation of **User System**, the contents of which shall include but not limited to:

- **Operational Diagram** at the **Connection Point**,
- switching procedures and requirements during normal and emergency conditions,
- procedures during Black Start and **Grid System** restoration, if any,
- process for request of planned and unplanned outages,
- safety procedures (Safety Rules) for coordinating, establishing, and maintaining the necessary isolation and earthing when required,
- post-commissioning monitoring and validation (also see Section 7.3),
- other communication/ coordination which includes personnel, boundaries, maintenance, exchange of information and incident reporting, and
- **Developer's** authorised and competent person/engineer.

The **OM** shall be reviewed by the parties involved from time to time and the parties may jointly revise the **OM** by mutual written agreement. Upon such revision, the revised **OM** shall apply.

5. Study Guidelines

The connection to the **Transmission Network** shall be based on technical criteria and judgement through a comprehensive Grid System Study. This section therefore specifies the scope of study under the responsibility of the **Developer**, which must be carried out with respect to the following:



Upon request by the **Developer**, Grid System data will be provided by the **TNSP Network Planner** subject to signing of a Non-disclosure Agreement (NDA). The Grid System Study is to be conducted in accordance with the standards below, and any amendments thereof:

i. The Electricity Rules, 2003 (State Grid Code)
ii. Engineering Circular No. 16/2021 "Guidelines and Requirements for System Integration Study"
iii. "Transmission System Operation Standard (TSOS)" issued by SESCO

5.1 Scope of Study

The scope of the study shall be discussed and agreed by the **TNSP Network Planner** and **GSO** with consideration on the specific scope of works, category, and electrical characteristics of the **Plant**. The Stage 1 Planning & Development (P&D) Study shall include, but not limited to, the following scope:

No	Scope	P&D Requirements
1	Steady-state power flow	• To evaluate the Grid System's adequacy to accommodate the power delivered by the Plant without violating the thermal limits of transmission elements under normal conditions. • Shall consider various operating conditions/ scenarios to reflect the Plant's intermittency behaviour.
2	Contingency analysis	• To identify the impact on the Grid System with respect to the power-flow thermal limits and voltage stability during loss of transmission element and system contingencies.

3	Short Circuit analysis	• To ensure adequate short circuit ratio for Grid System stability. • To calculate the minimum and maximum short circuit current contribution from the Plant at the Connection Point in the event of fault under various system conditions and scenarios. • To decide the required short circuit ratings for equipment selection. • To identify mitigations (if needed) to ensure short circuit level remains within limits or when there's limited infeed of fault current.
4	Reactive Power requirements	• To assess the reactive power capability of the Plant and voltage profile at the Connection Point and its vicinity. • To summarise PQ/PV diagrams comparing Plant capability vs. requirement. • To determine the need (if any) to install reactive power compensation equipment to meet the reactive power requirements.

The Stage 2 System Impact Study (SIS) shall include, but not limited to, the following scope:

No	Scope	SIS Requirements
1	Repeat Stage 1 P&D Study	• To reevaluate the impact of the new connection to the Grid System using actual models and design parameters, which are available during design and engineering stage. • To reassess the ability of the Plant to comply with the technical requirements using actual models and design parameters, which are available during design and engineering stage.
2	Transient Stability analysis	• Transient angle stability and impact on critical fault clearing time from the connection of the new Plant during system contingencies. • Load-generation frequency stability of Solar PV Systems connected to the Grid System during system contingencies and intermittency. • Voltage and frequency excursions of the Grid System and at the Connection Point with the new Plant during system contingencies. • Plant reactive power/voltage and active power/frequency controls.
3	Fault Ride-Through capability	• To identify the fault ride-through capability of the Plant for faults in the Grid System in accordance with specified frequency and voltage ride-through envelopes. • To identify inverters' performance during fault and upon clearance. • To verify the AC voltage and active power recovery of the Plant under different dynamic conditions and fault scenarios. • Simulate unbalanced faults to assess ride-through during opening and reclosing of a transmission line connecting the Plant (if any) and change in the phase angle of individual voltage phases.
4	Power Quality (PQ) requirement	• This includes voltage sag and swell, voltage and current harmonics, flicker, phase unbalance studies, etc. during normal operation, ramping or tripping, equipment energisation or switching. • To assess quality of service at the Connection Point to ensure it remains within the allowable limits as specified. • Determine the range, in the R-X plane, of the Transmission Network harmonic impedances and the pre-existing background voltage harmonics at the Connection Point (frequency scan). • Utilise PQ data from field measurement as far as practically feasible. • To include Thevenin model for each harmonic and the balance of plant model (cables, filters, etc.) for the entire operating range.

		• To determine the need (if any) of modification to the design of the Plant and/or to install filters/ compensation equipment to meet the PQ requirements.
5	EMT Study (electromagnetic transient)	• On case-by-case basis, if required by TNSP/GSO, specific ride-through, PQ, switching/energisation, control interaction and resonance studies shall be performed using EMT-type simulations. • Developer shall convert the given Grid System data into PSCAD format (reduced Thevenin model is accepted with accuracy verified by simulation); where vendor specific EMT models are used in the studies, these shall be provided.

The results of the Grid System Study are to be benchmarked against relevant clauses in the **Grid Code** and TSOS and the pertinent performance standards specified in Section 6 of this document. Any violation to the codes and standards due to the **Plant's** connection to the **Grid System** are to be highlighted in the report and mitigation option is to be proposed appropriately.

The System Impact Study (design evaluation) is an engineering evaluation before the Grid connection and plant commissioning to verify that the **Plant**, as designed, and its interactions with the **Grid System**, as applicable, meet the requirements of this standard. This evaluation does not include testing, though reports derived from factory test results may be consulted in the design evaluation.

5.2 Model Submission

Prior to the commencement of the Grid System Study, upon the formal application for connection, the **Developer** shall submit models of the **Plant**, its **Solar PV System(s)**, and supplemental device(s). While standard or generic models can be accepted for Stage 1 Planning & Development Study (less details available during planning stage), actual parameters and precise models, which are available during design and engineering stage, shall be applied for the Stage 2 System Impact Study.

At the minimum, the models shall represent the following (also refer Annex G in IEEE 2800):

Steady-State Models:

- Aggregate generator model (lumped inverter units)
- Single lumped unit transformer
- Equivalent reticulation impedance
- Single main EHV transformer
- Connection Facilities

Dynamic Models:

- Time varying irradiation profile
- Solar PV inverter and DC power output of the PV panels for the given level of solar irradiation
- Maximum power point tracker (MPPT) control (if any)
- Converter/ Electrical control of the inverter and PPC
- Voltage and frequency ride-through capabilities

All submitted models are to be provided together with the relevant documentations:

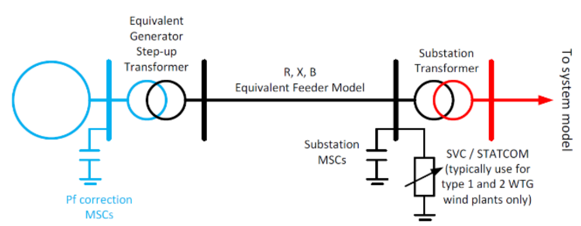
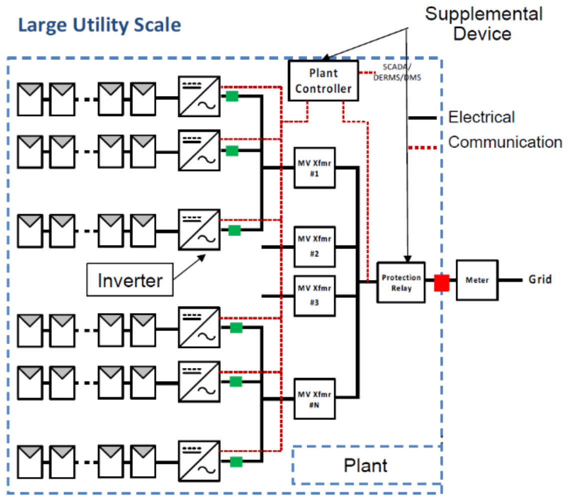
i. Description of the models and associated parameters to be used;

ii. User operation manuals, which explain the operational procedures specific for the Plant such as modes of operation, DC V-I characteristic, control strategy etc.;

iii. User application guides such as model development process, data setting and setpoint change;

iv. Model block diagrams for all control systems; and

v. Input data format and associated values of parameters.

<table>
<tr><th>Lumped Model using Equivalent <u>Plant</u> Models</th><th>Detailed Model using <u>Equipment</u> Models</th></tr>
<tr><td>
</td><td>
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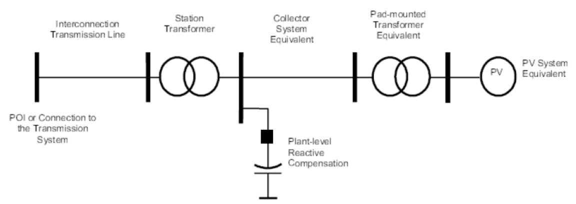
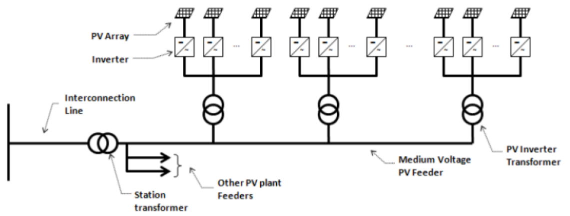
<tr><td>
</td><td>
</td></tr>
<tr><td>Typically used for steady-state RMS-type studies like power flow, contingency analysis, short circuit, and transient stability</td><td>Equipment level studies such as fault ride-through, PQ and EMT-type would generally require detail modelling of individual solar PV, inverter units, and/or supplemental device(s)</td></tr>
</table>

Developer shall develop an equivalent collector system model for power flow analysis based on either the NREL method (Muljadi et al.) or the ERCOT approach (Cheng et al.), or any other documented and technically reasonable methodology, from the detailed power flow model and compare the results between both (see above), before submitting both models in PSSE or any simulation software format as agreed by **SESCO**. Additionally, if the compiled model is submitted as user-defined model, a complete set of source codes (Flecs and/or Fortran codes) shall be submitted to **SESCO**. The accompanying control block diagrams must represent the corresponding model source codes.

It is critical that models provided are accurately structured and parameterised as well as reflect the actual installed equipment in the field for system study purposes and to help ensure reliability and consistency of the System Impact Study. The **Developer** shall make every effort possible to provide credible models to **TNSP Network Planner** and **GSO** for various studies. Model verification may be informed by the results from type tests if available.

For approximations that are made while developing the models, the technical reference that provides the relevant background and justification should be cited. If such a reference(s) is not available, a detailed explanation related to the said approximations should be provided. In either case, the resultant model should be shown to provide a proven behaviour.

6. Capability and Performance Requirements

6.1 Applicable Voltages and Frequency

The **Plant** shall not energise the **Connection Facilities** when it is de-energised, except for Black Start Plants at the discretion of the **GSO**. **Solar PV Systems** shall have the capability to remain in service while not exporting or importing active power, except for importation of active power to cover losses.

Unless specifically initiated by the **GSO**, the applicable voltages and frequency specify the necessary conditions at the **Connection Point** for which the **Plant** is permitted to enter service. When entering service or returning to service[1], the **Plant** shall not output active power to the **Grid System** until the applicable voltage and applicable frequency are within the ranges specified below.

Enter service is defined as begin continuous operation of the inverter-based resource (IBR) with an energised **Transmission Network** (adapted from IEEE 1547).

Table 6.1 Grid System voltage ranges (adapted from Grid Code)

Under **Normal Operating Conditions**	± 5% at **Transmission Network** nominal voltage of 500/400 kV ± 5% at **Transmission Network** nominal voltages of 275 kV and 132 kV ± 5% at **Distribution Network** nominal voltages of 33 kV and 11 kV + 5% and - 10% at **Distribution Network** nominal voltages of 415 V and 240 V
Under **System Stress** conditions or following **System** fault	± 10% at all **Grid System** voltages, however in the case of **Transmission Network,** this condition should not occur for more than 30 minutes.

Table 6.2 Grid System frequency ranges (adapted from Grid Code)

Under **Normal Operating Conditions**	49.5 Hz to 50.5 Hz
Under **System Stress** conditions	49.0 Hz to 51.0 Hz
Maximum operating band for frequency excursions under **System** fault conditions.	48.75 Hz to 51.25 Hz
Under extreme **System** fault conditions all sets should have disconnected by this frequency unless agreed otherwise in writing with the **GSO**,	51.5 Hz or above and 47.5 Hz or below

[1] Return to service: Enter service following recovery from a trip.

6.2 Reactive Power/ Voltage Control

6.2.1 Reactive power capability

Solar PV Systems shall have the capability to provide reactive power support when the primary energy source is available and not available, and during the transition between these two resource availability states. The **Plant** shall have the capability to inject/absorb a minimum reactive power defined by:

$|Q_{min}| \geq 0.4843 \times$ **MCR** or a power factor of 0.90

The minimum reactive power capability requirement when the active power output is less than 10% **MCR** is reduced as shown in Figure 6.1. Exchange of reactive power may require the **Plant** to consume active power from the **Grid System** due to losses when there is no available primary energy source.

Reactive power capability shall be dynamic as defined in Table 6.3. Figure 6.1 only shows the minimum range for the reactive power capability required. The **Plant's** actual capability may be outside of the black box, as registered with the **Single Buyer** and **GSO** in the **Capability Limits**.

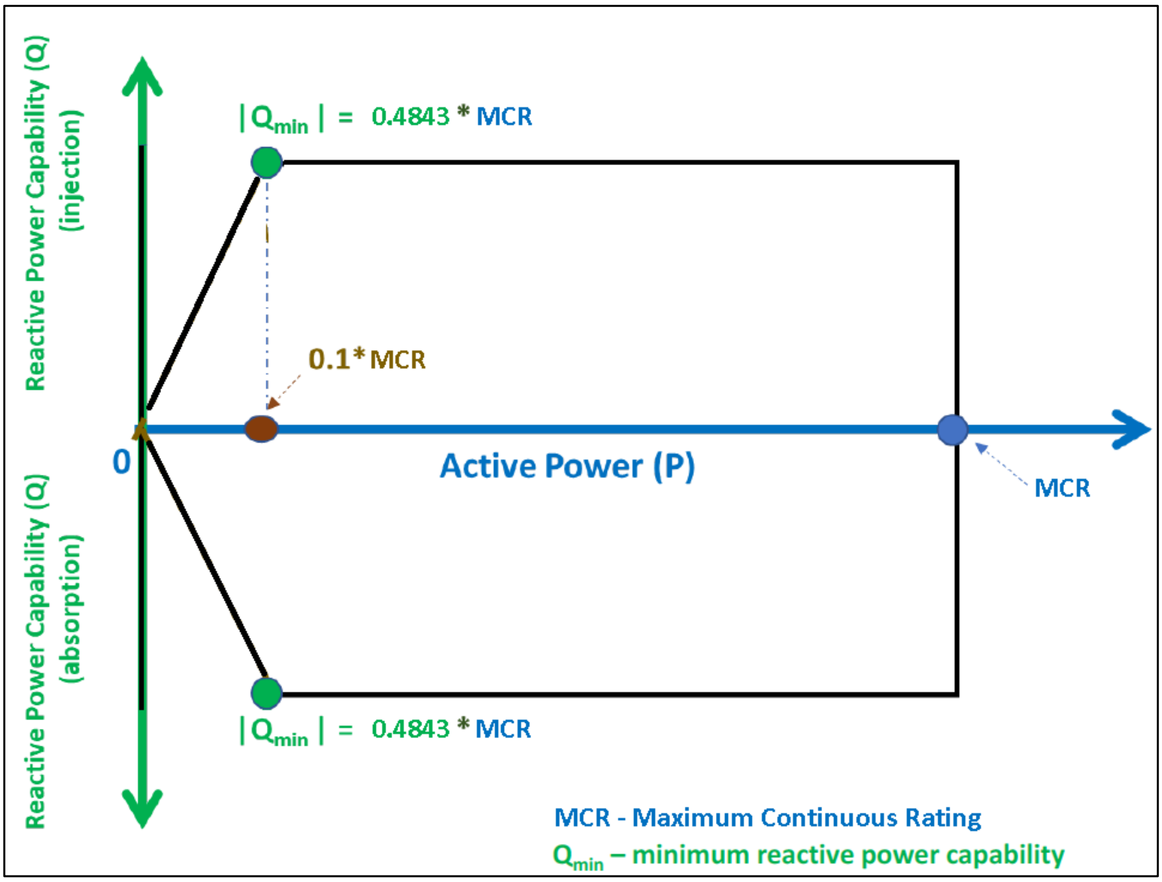


Figure 6.1 Minimum reactive power capability – Q versus P (adapted from IEEE 2800)

Minimum reactive power capability of the **Plant** for continuous and up to 30-min operation as required in Figure 6.2 shall be met within the applicable default voltage range specified. Any switched shunts or transformer tap change operation needed to restore the dynamic reactive power capability in Figure 6.2 shall be automatically controlled and shall respond within 60s.

Reactive power/current limiters shall only be utilised to protect equipment and/or personnel, not to restrict the reactive power capability.

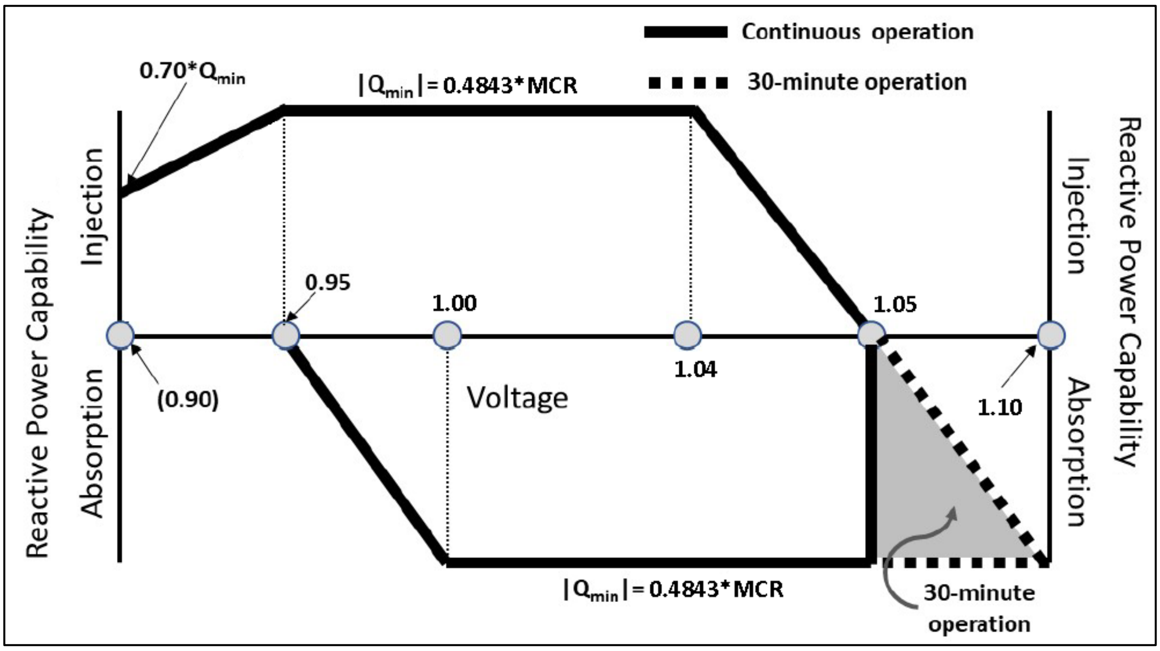


Figure 6.2 Minimum reactive power capability – Q versus V (adapted from IEEE 2800)

6.2.2 Voltage and reactive power control modes

The **Plant** shall provide voltage regulation capability by changes of reactive power output whenever the voltage is in the continuous operation region. The **Plant** shall provide the capabilities of the following mutually exclusive operating modes of reactive power control functions:

- Voltage control (default mode),
- Power factor control, and
- Reactive power set point control.

The closed-loop automatic voltage control shall be continuously acting to regulate the steady-state voltage at the controlled bus to the reference value with accuracy within 1% of the voltage set point. The voltage control system shall be capable of reactive power droop to provide a stable and coordinated response. Typical droop setting range is 0 to 3%.

The minimum dynamic reactive power response of the **Plant** to a step change in the voltage within the continuous operation region and within the **Plant's** reactive power capability shall be as specified in Table 6.3. Stable and damped response shall take precedence over response time.

Table 6.3 Performance target range to a voltage step change (adapted from IEEE 2800)

Performance Index	Acceptable Range
Reaction time	< 0.2sec
Step response time (0-90%)	< 2.0sec
Maximum overshoot	< 10%
Damping ratio	> 0.3

Depending on the operating modes, the voltage set point, target power factor and reactive power (inject or absorb) as applicable shall be specified by the **GSO**.

6.3 Active Power/ Frequency Response

6.3.1 Ramp rate

Active power shall increase approximately linear with an average rate-of-change not exceeding the **Maximum Continuous Rating (MCR)** divided by the enter service period. The duration of the enter service period shall be adjustable over a range of available settings of 1s to 1000s with a default time as specified by the **GSO**. The current default time is 400s, which indicates that the ramp rate(s) setting shall not exceed 15% of **MCR** per minute.

This requirement is a maximum ramp rate requirement, and the **Plant** may increase output at a slower rate than specified. This ramp rate shall NOT restrict the MW output during frequency response. For **Primary Reserve** and **High Frequency Response**, the maximum available power ramp rate of the **Plant** shall be as fast as technically feasible. The **SPP** shall inform the **GSO** about this limitation, if any.

6.3.2 Droop and Deadband

The frequency controller shall continuously be in **Frequency Sensitive Mode** and shall have fixed droop characteristics and the frequency droop parameters shall be capable of adjustment at least to the ranges of available settings from 2% to 5%. Frequency droop shall be based on the difference between **MCR** and zero output such that the slopes of the droop curves are always constant.

For most LSS plants, where the energy conversion does not involve any mechanical or moving parts, the sudden amount of change in the power output of the **Plant** may be possible and smaller values of droop are possible to provide larger and faster frequency response, as specified in Section 6.3.3. Currently, the default is set to 2%. Of course, much care should be taken to confirm system stability is maintained and unnecessarily large gains in the control are not used.

The permissible deadband of the controller should not be greater than 0.04Hz (for the avoidance of doubt, less than ± 0.02Hz or 0.04% of nominal frequency).

6.3.3 Primary Reserve and High Frequency Response

Primary Reserve capability shall be an autonomous function that is automatically self-deployed by the **Plant** and shall provide a fast and short-term temporary active power response to frequency deviations. This response is released with time over the period 0 to 5s from the time of initial frequency change and becomes fully available by 5s, and which is sustainable for at least a further 25s as long as the primary energy source is available (see definition of **Primary Reserve**).

The closed-loop dynamic response of the active power-frequency controller of the **Plant**, for a step change in frequency, shall have the capability to meet or exceed the performance specified in Table 6.4. The response shall be stable, and any oscillations shall be positively damped with a damping ratio of 0.3 or higher. Stable and damped response shall take precedence over rise time and settling time.

Table 6.4 Parameters of frequency response dynamic performance (adapted from IEEE 2800)

Performance Index	Acceptable Range
Reaction time	< 0.2sec
Rise time (10-90%)	< 2.0sec
Settling time within 2.5% of change	< 10sec
Damping ratio	> 0.3

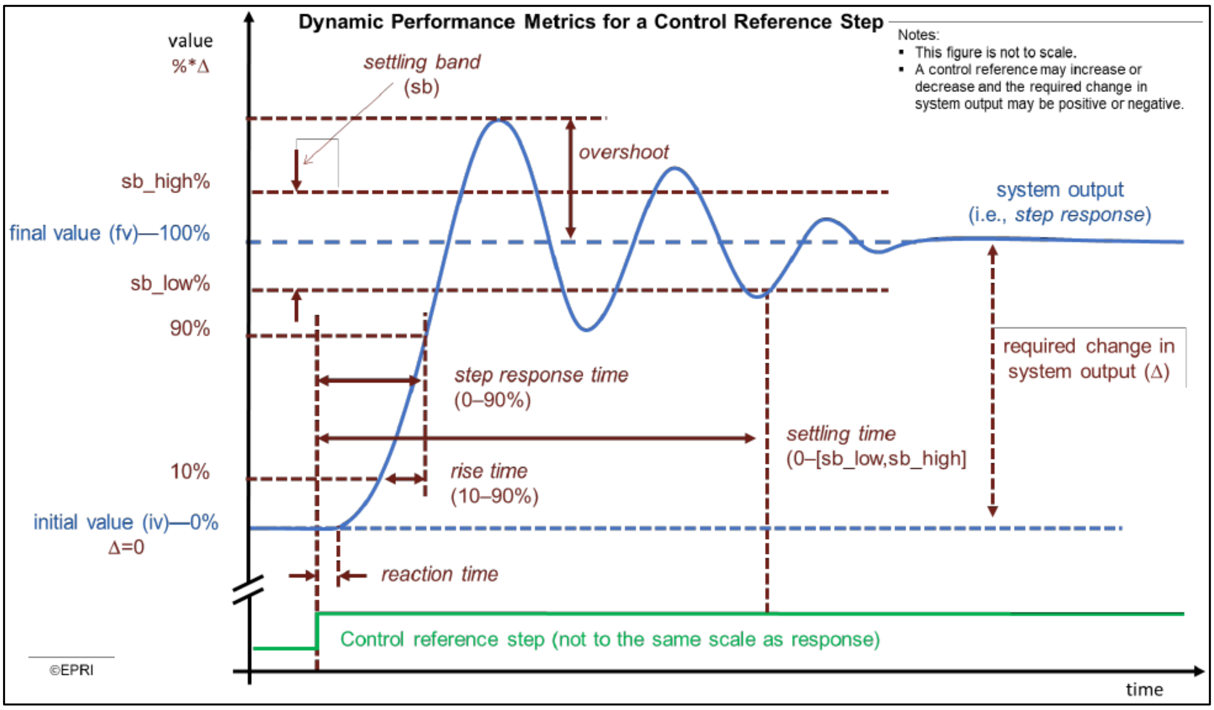


Figure 6.3 Dynamic performance metrics for a control reference step (from EPRI)

The **Primary Reserve** and **High Frequency Response** shall include the capability to respond to:

- under-frequency disturbances by active power increase while limited by the available active power (either **MCR** or temporarily short-term rating).
- over-frequency disturbances by active power decrease while limited by the **Plant Minimum Generation (PMIN)**.

If/When required by the **GSO**, should the **Plant** be operating with a headroom (curtailed operation), capability to dynamically maintain this headroom while the primary energy source is varying, and response to under-frequency disturbances shall be required. Pre-curtailment or other measures to provide frequency response reserve may be included.

The **Plant** shall be capable of sustaining primary frequency response for as long as the primary energy source is available. Total active power output may be capable and allowed to temporarily (less than 1 min) exceed the **MCR** up to its short-term rating. Response to over-frequency disturbances (**High Frequency Response**) shall not be required for **Plant** operating at **PMIN**.

The tuning of dynamic performance parameters shall be carefully studied on a case-by-case basis to help ensure it does not inadvertently result in oscillatory behaviour or unnecessary curtailment. Particular attention should be given to the potential for adverse interaction with the torsional oscillation modes of synchronous turbine-generators connected to nearby **Transmission Network**.

6.4 Fault Ride-Through

The voltage and frequency ride-through requirements shall take precedence over voltage control and frequency response and shall apply to three-phase and line-to-ground faults.

The **Plant** shall be designed to provide the voltage and frequency disturbance ride-through capabilities specified in this section. Any tripping of the **Plant**, or other failure to provide the specified ride-through capability, due to its self-protection as a direct or indirect result of a voltage or frequency disturbance within a ride-through region, shall constitute non-compliance with this standard.

6.4.1 Voltage

For a given voltage, the **Plant** shall not trip until the time duration at this voltage exceeds the specified minimum ride-through time duration. The **Plant** shall ride through when the applicable voltage exceeds or is less than the voltage representing the operation regions except for time durations exceeding those specified in Table 6.5 and Figure 6.4.

Table 6.5 Voltage Ride-Through Requirements (adapted from IEEE 2800)

Ride-Through	Applicable Voltage (p.u)	Minimum Ride-Through Time (sec)
High Voltage	V > 1.20	Determined by Capability Limits
	V > 1.10	1.0 (Mandatory); 3.0 (Permissive)
Continuous Operation	0.90 ≤ V ≤ 1.10	≥ 1800
Low Voltage	V < 0.90	6.00
	V < 0.70	3.00
	V < 0.50	1.20
	V < 0.25	0.32
	V < 0.10	0.32

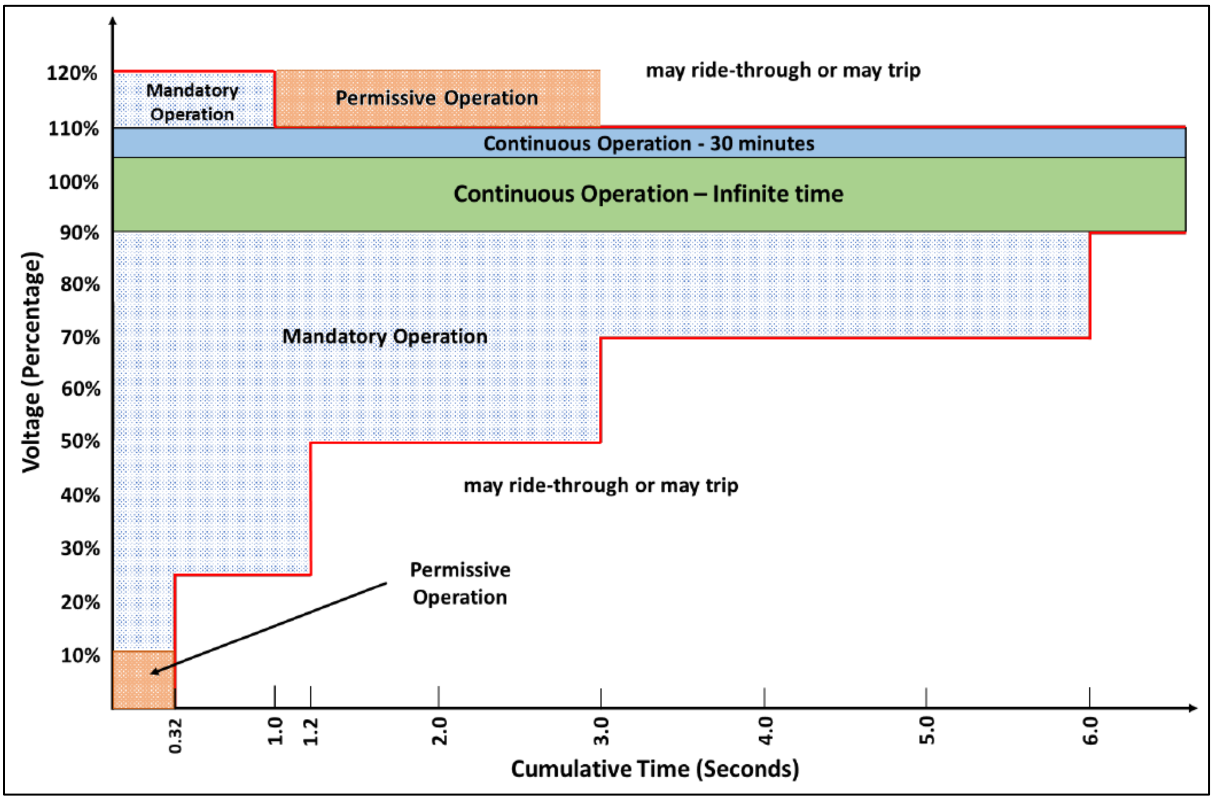


Figure 6.4 Illustration of Voltage Ride-Through Requirements

For voltage disturbances of any duration within the continuous operation region, the **Plant** shall remain in operation, and shall continue to deliver pre-disturbance level of active power. Current blocking is not permitted during continuous and mandatory operations.

During a ride-through mode including both balanced and unbalanced fault conditions, the **Solar PV System** shall be capable of injecting current up to its maximum limit. The **TNSP/GSO** requires that:

- ample amount of reactive current injection (reactive current priority mode) during low-voltage ride-through to support voltage and to activate protective devices;
- no reduction in active current injection during high-voltage ride-through operation to support frequency during the fault;
- the response upon fault inception and fault clearance shall be within a step response time of 2.5 cycles and settling time of 4 cycles; and
- current injected to have the same fundamental frequency as the terminal voltage.

The **Plant** shall ride-through multiple excursions outside of the continuous operation region to cover reasonable tripping and reclosing sequence associated with short-circuit faults on **Transmission Network** or system dynamic voltage oscillations. The **Plant** is expected to ride-through opening and reclosing of a transmission line connecting the **Plant** to the **Transmission Network**. The **Plant** shall remain in operation for any change in the phase angle of individual voltage phases, of less than or equal to 25deg, caused by occurrence and clearance of unbalanced faults. Exception from this voltage angle deviations ride-through is allowed with mutual agreement between the **SPP** and **TNSP/GSO**.

The **Solar PV System** shall maintain automatic voltage control during a ride-through mode. Upon the applicable voltage returning to the continuous operation region from ride-through mode, the **Plant** shall have capability to restore active power output to 100% of pre-disturbance level.

6.4.2 Transient overvoltage

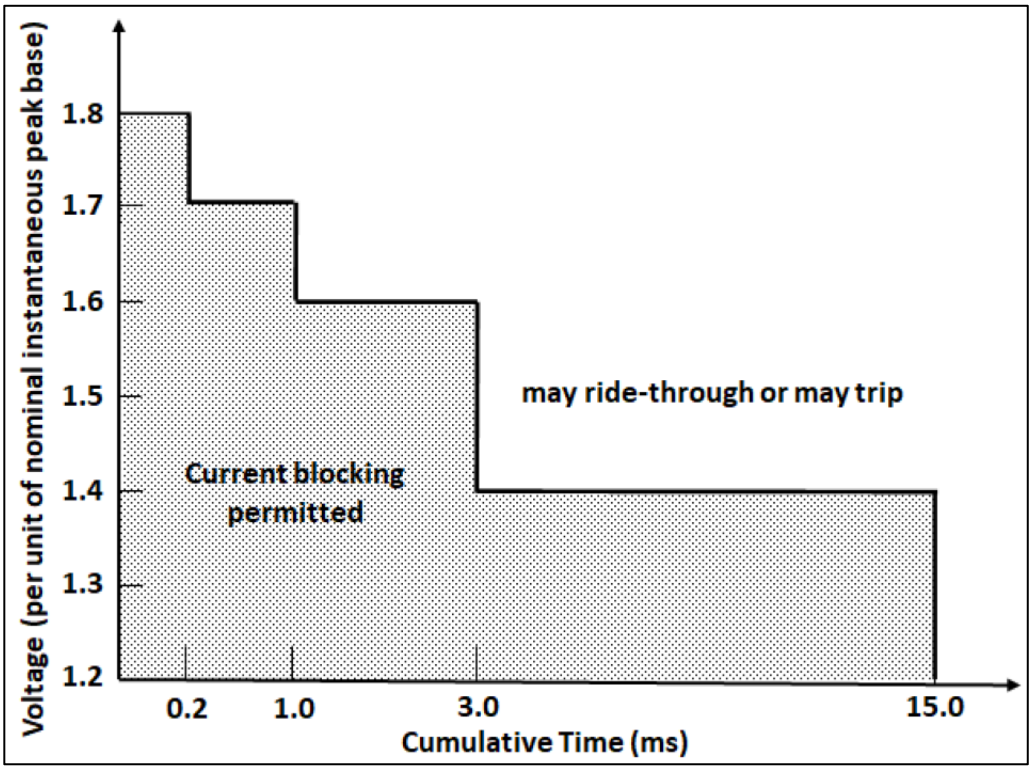


Figure 6.5 Transient overvoltage ride-through requirements (adapted from IEEE 2800)

The **Plant** shall ride through transient overvoltage for which the greater of individual phase-to-phase or phase-to-ground instantaneous voltage magnitudes do not exceed the cumulative durations (minimum time) specified in Figure 6.5. The intent of transient overvoltage ride-through requirements is to ensure that the **Plant** does not trip during switching events in the **Transmission Network**.

The voltages in Figure 6.5 shall be per unit of the nominal instantaneous peak voltage. For example, in case of a **Plant** connecting to voltage of 275 kV_{rms} phase-to-phase RMS, the phase-to-phase instantaneous peak voltage is 388.9 kV_p (275 × √2), and the phase-to-ground instantaneous peak voltage is 224.5 kV_p ((275/√3) × √2).

6.4.3 Frequency

The minimum capability shall be no less than the continuous operation or mandatory operation capability regions shown in Figure 6.6.

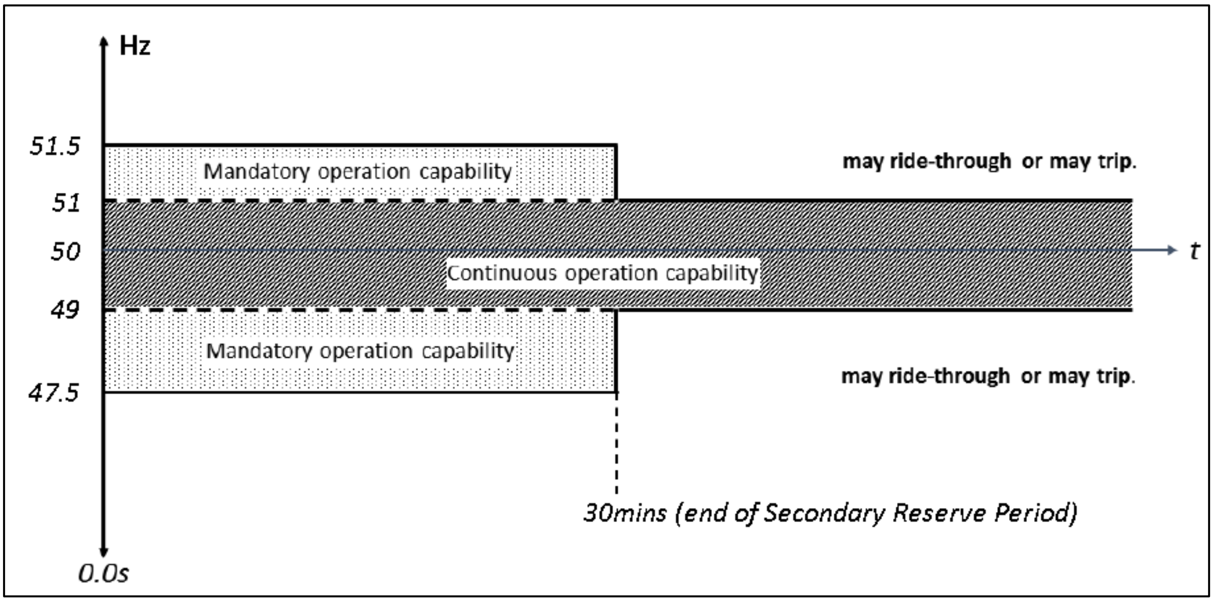


Figure 6.6 Frequency Ride-Through Requirements (adapted from IEEE 2800)

When the applicable frequency is within the required continuous operation region, the **Plant** shall exchange active and reactive power with the **Transmission Network** within its **Maximum Continuous Rating (MCR)** and within the **Capability Limits** in accordance with **Primary Reserve** and **High Frequency Response** control requirements as applicable.

During temporary frequency disturbances within the mandatory operation region, the **Plant** shall modulate active power to mitigate the underfrequency and overfrequency conditions as specified in Section 6.3.3 for at least 30mins. The **Plant** shall maintain in synchronism with the **Transmission Network** and maintain its reactive power output.

Operation outside of mandatory operation region is determined by V/Hz capability limits of **Solar PV System**, transformers and Supplemental devices.

6.5 Power Quality (PQ)

6.5.1 Voltage fluctuations and flicker

The **Plant** shall not create unacceptable rapid voltage changes or flicker at the **Connection Point** in accordance with the **Grid Code**, except for slow voltage variations caused by cloud shadow passage.

For frequent events such as energisation of transformers, frequent switching of capacitors, or from abrupt output variations caused by **Plant** misoperation, the **Plant** shall not cause rapid voltage changes at the **Connection Point** to exceed 2.5% of nominal voltage. The method for defining compliance with this requirement shall be as specified in IEC 61000-4-30:2015 and any amendments thereof.

For infrequent events such as unplanned tripping, switching or energisation during commissioning, fault restoration, or maintenance, the limit shall include the following characteristics:

- The minimum voltage shall be no less than 90% of the initial RMS voltage V_O.
- Within 2s, the voltage shall recover to its final RMS voltage V_F.
- The initial V_O and final V_F shall be within the nominal voltage range in Table 6.1.

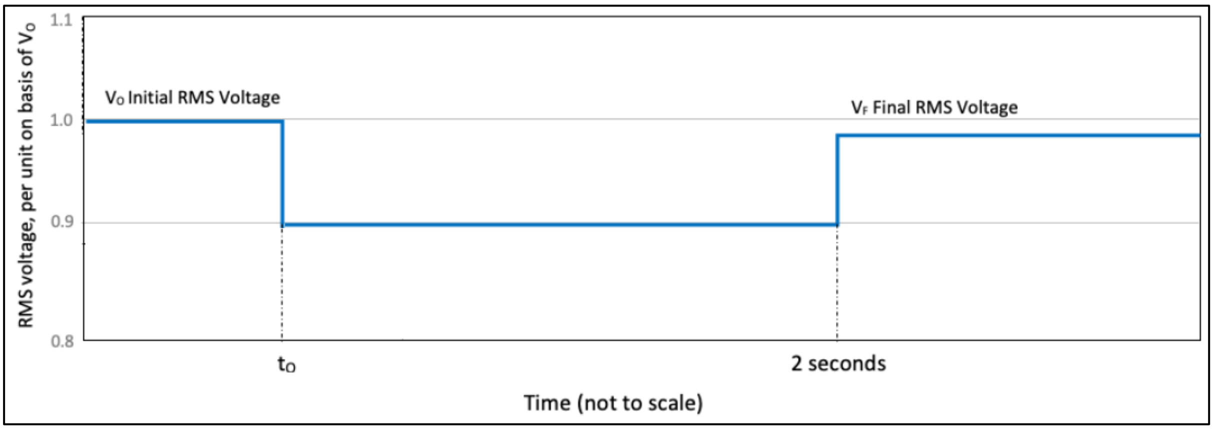


Figure 6.7 Minimum acceptable voltage due to infrequent events (adapted from IEEE 2800)

Assessment and measurement methods for flicker are defined in IEEE Std 1453 and IEC TR 61000-3-7. The 95th percentile value of the measurements should not exceed the emission limit based on a one-week measurement period. The **Plant** contribution (emission values) to the flicker applied at the **Connection Point**, irrespective of the voltage level, shall not exceed the greater of the limits listed below and the individual emission limits determined:

- $E_{Pst} < 0.35$, being the emission limit for the short-term flicker severity P_{st}.
- $E_{Plt} < 0.25$, being the emission limit for long-term flicker severity P_{lt}.

6.5.2 Harmonic current and voltage

Harmonic current distortion, interharmonic current distortion, and total rated-current distortion (TRD) at the **Connection Point** shall not exceed the limits stated in Table 6.6. Any aggregated interharmonics current distortion between two harmonic orders shall be limited to the specified lesser magnitude limit of the two.

The 95th percentile value of the harmonic measurement shall not exceed the emission limit based on a one-week measurement period (measurement of harmonics to the 50th order requires meters compliant with IEC 61000-4-30 Class A).

Table 6.6 Maximum current distortion in percent of rated current (adapted from IEEE 2800)

Voltage Level (kV)	Even Harmonic Order *h* (%)			Other Individual Harmonic Order *h* (%)			TRD (%)[2]
	$h = 2$	$h = 4$	$h = 6$	$h < 11$	$11 \le h < 17$	$17 \le h \le 50$	
132kV	1.0	2.0	3.0	1.5	1.0	1.0	2.0
275kV	1.0	2.0	3.0	1.5	1.0	1.0	2.0

Prior to the **Plant** connection, **SESCO** and **Developer** shall coordinate the creation of a baseline of the voltage harmonics at the **Connection Point** for future comparison. The requirements in Engineering Circular No. 11/2023 "Grid System Power Quality Meter Requirements" shall be applicable (IEC 61000-4-7 Class I, IEC 61000-4-30 Class A and IEEE Std 519 among others). Harmonic measurements and adherence to the limits shall be applicable at the time of commissioning of the **Plant**. The applicability after commissioning may depend on **SESCO** requirements.

Based on IEEE Std 519 or IEC TR 61000-3-6, **SESCO** would set objectives on harmonic voltage distortion levels in AC network to reduce potential negative effects on **Users** and network equipment. Based on the knowledge of its own network characteristic and existing or future background harmonic voltage level, **SESCO** would specify voltage harmonic limits for the **Plant** at the **Connection Point**.

For **Transmission Network**, the maximum total level of harmonic on the existing and any future system from all sources under both scheduled outage and forced outage conditions must not exceed a total harmonic distortion (THD) of 2% with no individual harmonic greater than 1.5% (CC5).

The **Developer** should coordinate remedy measures, as needed, with **SESCO** to meet the harmonic voltage distortion requirements. The verification of the harmonic performance, which can be done by field measurements over a period of time, is necessary to cover the different network configurations and background harmonics.

Once the **Plant** is in commercial operation, the **SPP** should only be responsible for ensuring that the harmonic characteristics of the **Plant** are maintained within the ranges of values considered in the initial study. The **GSO** may require on-site testing and measurement to verify the data and the hypothesis used in the System Impact Study.

6.6 Protection

The protective functions of the **Plant** shall be coordinated with those of the **Transmission Network**, where applicable. Any applied protection in the **Plant**, including but not limited to the following, shall not impede/ limit the **Plant** from meeting the ride-through requirements of this standard:

- Protections applied to **Plant** auxiliary load,
- Frequency or Rate of change of frequency (ROCOF) protection (**SESCO** and the **SPP** shall coordinate the underfrequency load shedding (UFLS) scheme in the area, if applicable),
- AC voltage protection (**SESCO** and the **SPP** shall coordinate the undervoltage load shedding (UVLS) scheme in the area, if applicable),
- AC overcurrent protection, and
- Unintentional islanding protection.

[2] Note that Table 6.6 differs from IEEE Std 519, with the new term total rated-current distortion (TRD), which includes all frequencies up to 50th order, and is based on rated current capacity on Plant MVA rating

6.7 Supplemental Devices

Supplemental devices other than inverter units may be used to achieve compliance with the requirements of this standard. Examples include equipment such as energy storage (ESS), capacitor banks, STATCOMs, harmonic filters, protective devices, and Power Plant Controller (PPC), etc.

While the **Plant** may be composed of individual inverters performing its own energy production, the PPC shall provide the following plant-level control functions:

- Dynamic voltage and/or power factor regulation of the **Plant**.
- Frequency control to change **Plant** output with respect to **Grid System** frequency.
- Active power control following variation in Renewable Energy source.
- Ramp rate controls to ensure that the **Plant** output can ramp up or down within a specified ramp rate limit, to the extent possible.

The PPC implements plant-level logic and closed-loop control schemes with real-time commands to the individual inverters to achieve fast and reliable regulation. It relies on the ability of the inverters to provide a rapid response to commands from the PPC.

The PPC shall not prohibit or prevent controls of **Solar PV Systems** and any supplemental devices to meet ride-through performance requirements.

6.8 Dispatch and Forecast

The **Plant** shall be self-dispatch up to its maximum output for any period except when the delivery cannot be accepted by **GSO** due to transmission or system security reasons. The **Plant** shall be dispatchable at reduced load (curtailed operation) under certain conditions as instructed by **GSO**. The **GSO** shall disconnect the **Plant** under certain emergency conditions.

In this respect, it is mandatory for the **SPP** to submit its annual generation profile and maintenance schedule to the **Single Buyer** and the **GSO** for the purpose of planning, scheduling, and grid operation to minimise risks of wide deviation in generation dispatch.

The **SPP** shall indicate the declared **Availability** to **GSO** in an Availability Notice, in such manner or form (daily, weekly, rolling real-time) as may be prescribed from time to time by the **GSO**. The **SPP** shall specify their forecasted capacity (in MW_{ac}) of the **Plant's** output to be generated and delivered to the **Grid System** from the **Plant** for every fifteen (15) minutes interval or such other period as may be notified by the **GSO** to **SPP** in writing.

Due to its variability and intermittency, solar forecasting requirement is recommended to ensure the **SPP** adopts the advance weather forecast technology to provide accurate and reliable solar power output forecast for better planning in generation dispatches. The forecasting shall adopt IEC TR 63043:2020 or equivalent, which describes the common practices and technical guidance for Renewable Energy power forecasting technology, including general data demands, forecasting methods, and forecasting error evaluation as below:

- Input of Numerical Weather Prediction (NWP) technology for forecasting.
- Covers multiple spatial and temporal timescales (short-term, ultra-short-term and minute).
- Probabilistic forecasting and ramp event forecasting (deterministic).
- Error evaluation methods for deterministic and probabilistic.

7. Conformance and Validation Requirements

This section specifies the minimum test and verification requirements and methods applicable to each requirement specified in Section 6 above, and at which stages during the connection process testing and verification shall be required. All requirements of this standard shall be verified by a combination of the following methods as specified: type tests, design/ study evaluations, commissioning tests, and operational monitoring. These test requirements are neither to be used as an all-inclusive step-by-step testing manual nor as replacement for manufacturer commissioning test procedures.

No	Test	Requirements	Verification Methods
1	Applicable Voltages and Frequency	To ensure that the Plant complies with voltage and frequency range set out in Grid Code and TSOS. The design of the Plant must enable continuous operation within the voltage and frequency variation.	System Impact Study Operation Monitoring
2	Reactive power capability	Solar PV System shall be capable of continuous operation at any point within the minimum reactive power requirement.	System Impact Study Commissioning Tests Operation Monitoring
3	Voltage and reactive power control	Confirm functionality of all the control modes. To demonstrate that the controller can act continuously to provide steady-state control of pre-set terminal voltage, irrespective of the change in output power. The response of the controller to a step change in voltage shall have a damped characteristic and meet the required performance index. The stability of the voltage controller shall be assessed to be stable.	System Impact Study Commissioning Tests Operation Monitoring
4	Active Power/ Frequency Response	Verify the upper/lower operating range and ramp rate for the Plant as per registered capability. The controller shall be capable of being set and operate within the required droop range and permissible deadband. The controller shall automatically respond to change in Grid frequency and assist in the recovery to target frequency via regulating Active Power. To ensure that the Plant can meet the required frequency response performance index in Primary Response and High Frequency Response. The stability of the frequency controller shall be assessed to be stable.	System Impact Study Commissioning Tests Operation Monitoring
5	Fault Ride-Through	Solar PV System is required to operate through system faults and comply with the frequency and voltage ride-through envelopes. To identify the fault ride-through capability of the Plant under different dynamic conditions and balanced/unbalanced fault scenarios. Prove inverters' performance during fault ride-through and recovery upon clearance.	System Impact Study Operation Monitoring

6	Power Quality (PQ)	To demonstrate the connection of the Plant with the Grid System, at any time and condition, shall not cause any deterioration in the quality of service at the Connection Point.	System Impact Study Commissioning Tests Operation Monitoring
		To comply with allowable emission limits.	
7	Protection Coordination	To ensure that the Plant complies with fault clearing time criteria in Grid Code and TSOS.	Commissioning Tests Operation Monitoring
		Coordination of protection scheme and interlocking scheme between the Plant and Transmission Network.	
8	Measurement accuracy	Measured data and derived quantities shall meet or exceed the steady-state and transient measurement accuracy requirements specified.	Commissioning Tests
9	Compliance testing	TNSP/GSO may require further compliance tests or evidence to confirm site-specific technical/ performance requirements or compliance issues that are of particular concern.	Commissioning Tests
		Additional compliance test will be identified if needed, following TNSP/GSO review of submitted test procedures.	
10	Parameters measurement & Model validation[3]	To verify the Plant parameters associated with the submitted simulation models and the design characteristics.	System Impact Study Commissioning Tests Operation Monitoring
		To validate the submitted simulation models and associated parameters can replicate the response of actual tests with reasonable tolerance of error.	

7.1 Design Evaluation

In accordance with IEC 60904, IEC 61400-21-1, IEC TS 62910, IEEE Std 1547.1 or equivalent, the **Developer** shall submit type test reports and the factory acceptance test (FAT) reports on major equipment as promptly as possible after the completion of all such tests. Type tests shall be performed on **Solar PV System** as well as supplemental devices that are used to meet the requirement of this standard. For the avoidance of doubt, such reports shall not replace the obligations of **Developer** to carry out System Tests on the **Plant**.

The design evaluation (desktop study) is an engineering evaluation during the System Impact Study to verify that the **Plant**, as designed, or the **Solar PV System(s)**, as applicable, meet the requirements of this standard (also refer Section 5 above).

Some performance requirements, such as fault ride-through performance, cannot be verified based on type tests or factory acceptance tests (FAT) of individual equipment and/or commissioning tests of the **Plant**. The design evaluation using models and simulations is thus necessary to verify, to the extent feasible and possible, that the **Plant** meets these performance requirements.

[3] CIGRE TB727 recommends type of studies and tests for model validation (refer Appendix C)

7.2 Commissioning and Post-Commissioning

The System Tests are verifications conducted in the field on one or more **Solar PV System(s)**, supplemental devices, and/or the **Plant** to verify that the **Plant** as designed, delivered, and installed meets the requirements of this standard. The Power Plant Controller (PPC) aspect of the stability model is typically verified or calibrated with plant commissioning test results.

All commissioning tests shall be performed based on written test procedures. These test procedures shall follow good engineering practice and shall be subject to approval by the **GSO**. Commissioning tests may include operability and functional performance tests. The tests which may have a significant impact on the **Grid System** can only be undertaken at certain times of the day subject to **Grid System** constraints. **Developer** is required to submit advanced notification to **GSO** (refer Engineering Circular No. 11/2022 "Grid System Operation Procedures & Guidelines" and any amendments thereof) of such tests, including commissioning tests, conformance tests and validation tests.

During commissioning or post-commissioning stage, all submitted models and associated parameters shall be validated or verified through System Tests (refer Appendix C). The simulation should trend well with the measured data with critical part of the trace within 10% (±5%) error band. This accuracy requirement is applicable to the range between the minimum and maximum operating capability.

Prior to commercial operation, the **Developer** shall submit the fully validated models together with the final assessment report to **TNSP/GSO**. If the model does not produce the correct output, the model submission requirement will not be considered as complete until the errors are rectified.

The final settings as accepted by **GSO** (including control system parameters, applicable protection settings, etc.) shall be implemented and tested. **SPP/Developer** shall not adjust or modify the settings unless with the prior written consent from the **GSO**.

7.3 Operational Monitoring

Pertaining to OC10, operational monitoring consists of evaluating the **Plant's** performance in the field during operation, especially following system events where the voltage and/or frequency deviate from the normal operating region. Operational monitoring verifies that the **Plant** continues to meet the requirements of this standard over its operational lifetime (refer Appendix D).

With respect to OC11, the tests also include other compliance tests to be undertaken by **SPP** from time to time during commercial operation and shall be scheduled accordingly. The **GSO** may also notify **SPP** to conduct compliance tests to prove the performance of the **Plant**. Upon such notification by the **GSO**, the **SPP** shall then schedule the tests accordingly.

As to MC5.12, to aid with performance monitoring, event analysis, and disturbance-based model validation, the **SPP** shall take measurements at specified points throughout the **Plant**, from individual **Solar PV Systems** to the **Custody Transfer Point** and shall make these data available to the **TNSP/GSO**.

Where applicable, the collected data shall follow the IEEE C37.118 (PMU), the IEEE Common Format for Transient Data Exchange (COMTRADE) or the IEEE Power Quality Data Interchange Format (PQDIF).

All parameters that shall be measured and retained for performance monitoring and validation, shall meet or exceed the steady-state and transient measurement accuracy requirements specified in Table 7.1. Upon request by **TNSP/GSO**, the **SPP** shall provide the manufacturer stated actual steady-state and transient accuracy values of such measurements and derived quantities.

Table 7.1 Measurement and derived quantities accuracy requirements (adapted from IEEE 2800)

Parameter	Minimum Accuracy		Note
	Steady-state[4]	Transient[5]	
Voltage	± 2.5%	± 10%	Of nominal rated value
Current	± 2.5%	± 10%	Of nominal rated value
Frequency	± 0.01Hz	± 0.01Hz	For fundamental frequency
Active Power	± 5%		Of nominal apparent power
Reactive Power	± 5%		Of nominal apparent power

Operational metering confirms model validation and calibrates that the models supplied during the commissioning/ post-commissioning accurately represent the **Plant** as installed and configured in the field, as the design, equipment, and control settings may have changed since the initial modelling was performed. The outcome of this phase is a design record consisting of final specifications and models to be used by **SESCO** as representative of the state of the **Plant**.

Once the **Plant** is operational, system event data could be used to verify various plant-level models. When suitable event data are available and used to verify plant-level models, in case where simulated performance of the **Plant** does not closely match the performance observed during an event, the **SPP** shall provide updated models to **GSO** according to a schedule determined by the **GSO**.

Once the **Plant** is operational, modifications to controls that change the response of the **Plant** or **Solar PV Systems** as defined within this standard shall be mutually agreed upon between **GSO** and the **SPP**. The **SPP** shall provide updated models according to a schedule determined by the **GSO**.

The scope also includes tests to be undertaken upon modifications to the control systems or **Solar PV Systems** that may affect their performance or their connection to the **Grid System**. **SPP** shall notify the **GSO** in advance of their plans for such modification and seek the **GSO's** advice on the required tests. Upon the **GSO's** instruction, **SPP** shall schedule the required tests upon completion of the **Plant** modifications, prior to or during the recommissioning of the **Plant**.

IEC TS 63102:2021 or equivalent shall be referred for **Grid Code** compliance assessment methods for grid connection of LSS Plants. The electrical behaviour of LSS Plants consists of frequency and voltage range, reactive power capability, control performance including active power-based control and reactive power-based control, fault ride through capability and power quality. The assessment methods include simulation study, compliance testing, and post-commissioning monitoring. The input for compliance assessment includes relevant supporting documents, testing results and validated simulation models, and continuous monitoring data.

[4] Useful for applications such as voltage control and SCADA.
[5] Useful for applications such as dynamic voltage support, protection, and short-circuit contribution.

8. APPENDIX

[A] Flowchart on the Process of Grid System Connection for LSS

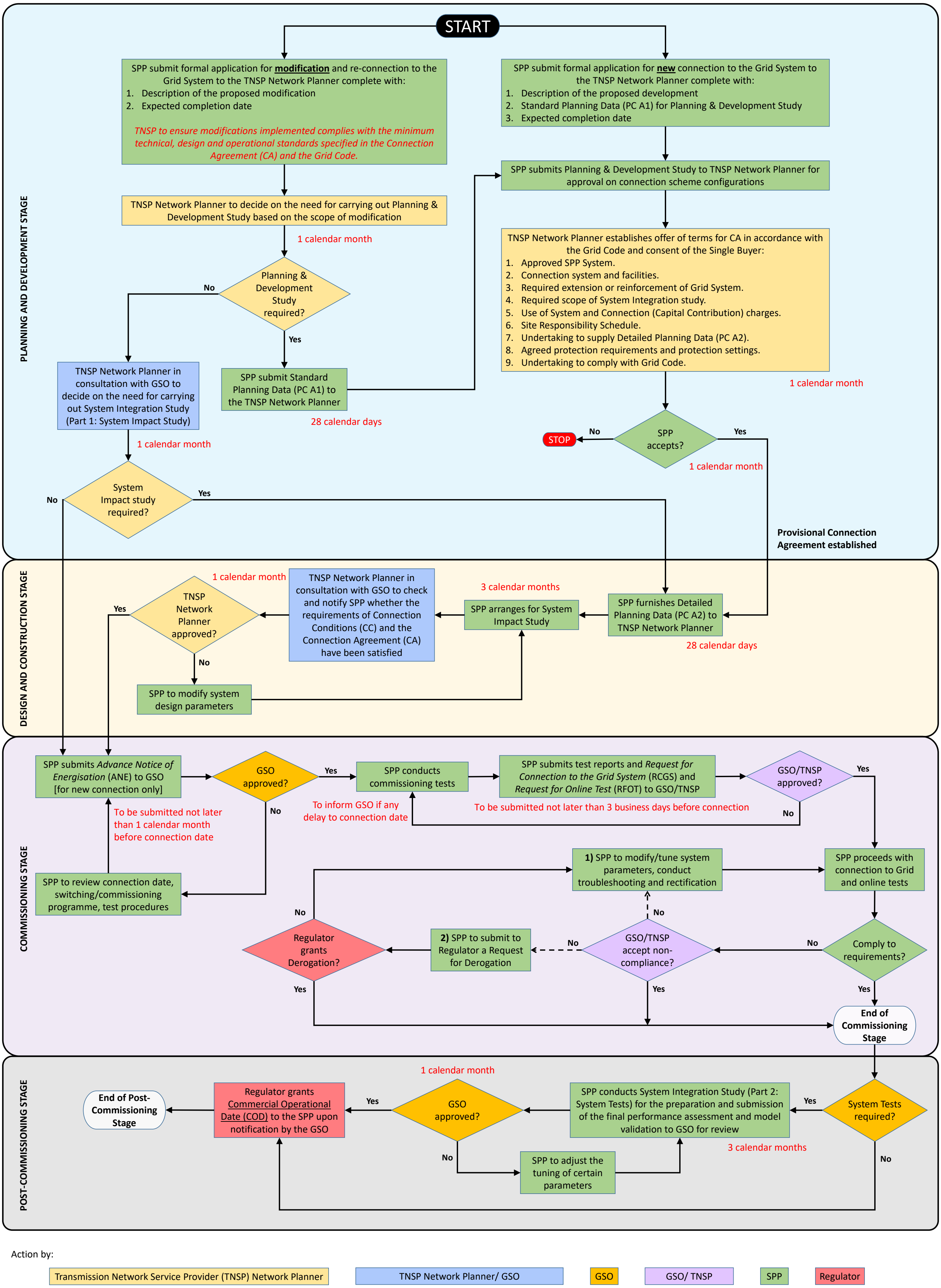
[B] Application Form for LSS Connection to the Grid System

[C] Type of Studies and Tests for Model Validation (CIGRE JWG C4/C6.35/TB727)

[D] Measurement Data for Performance Monitoring and Validation (IEEE 2800)

"The content presented in this Appendix is reproduced from external sources as quoted and is intended solely for reference purposes. Sarawak Energy will not be responsible for any consequences resulting from the use of this documentation as well as the reliance upon any information contained herein or for any omission."

Appendix A Flowchart on the Process of Grid System Connection for LSS



APPLICATION FORM FOR LSS CONNECTION TO THE GRID SYSTEM		
PROJECT TITLE		
DATE OF APPLICATION		**APPLICANT NAME**
EXPECTED CONNECTION DATE		
USER CATEGORY *(Select accordingly)*	**APPLICATION TYPE** *(Select accordingly)*	**AFFILIATION** *(Company, Utility, or Department)*
☐ Large Consumer ☐ Power Producer ☐ TNSP ☐ Interconnected Party	☐ New Connection ☐ Modified Connection	
CONTACT ADDRESS:		**TEL NO.:**
		FAX NO.:
		EMAIL ADDRESS:
PLEASE ATTACH OR ACKNOWLEDGE THE FOLLOWING IN YOUR SUBMISSION OF THIS APPLICATION FORM		
☐ A description of the User network to be connected to the Grid System or the modifications to User Network already connected to the Grid System (the 'proposed Development')		
☐ Standard Planning Data as listed in Part 1 of Appendix A of the Planning Code		
☐ Detailed Planning Data as listed in Part 2 of Appendix A of the Planning Code		
☐ A project time schedule of the proposed Development		
☐ The User is obliged to fully comply with the requirement of the "Guidelines and Requirements for Large-Scale Solar (LSS) Connection to Sarawak Grid System", referenced Engineering Circular No.11/2024, and any amendments thereof, issued by Sarawak Energy Berhad.		
APPLICANT SIGNATURE	**DATE**	**REMARKS**

TNSP NETWORK PLANNER SECTION ONLY	
TNSP NETWORK PLANNER SIGNATURE	
DATE	
REMARKS	

PLANNING CODE - APPENDIX A

PLANNING DATA REQUIREMENTS

PART 1

PC A1 STANDARD PLANNING DATA

PC A1.1 CONNECTION POINT AND USER NETWORK DATA

PC A1.1.1 General

All **Users** shall provide the GSSP Network Planner with details specified in PC A1.1 and PC A1.2 relating to their **User Network**.

(i) User Network Layout

Users shall supply single line diagrams showing the existing and proposed arrangements of the main connections and primary systems showing equipment ratings and where available numbering and nomenclature.

(ii) Short Circuit Infeed

User shall supply the following information;

(a) the maximum 3-phase short circuit current injected into the **Transmission Network**; and

(b) the minimum zero sequence impedance of the **User Network** at the point of connection with the **Grid System**.

PC A1.2 DEMAND DATA

PC A1.2.1 General

All **Users** with **Demand** in excess of 1 MW shall provide the GSSP Network Planner with **Demand**, both current and forecast, as specified in this PC A1.2 provided that all forecasted maximum **Demand** levels submitted to the GSSP Network Planner by **Users** shall be on the basis of corrected Average Hot Spell (AHS) Conditions.

In order that the GSSP Network Planner is able to estimate the diversified total **Demand** at various times throughout the year, each **User** shall provide such additional forecasts **Demand** data as the GSSP Network Planner may reasonably request.

PC A1.2.2 Demand (Active And Reactive) Data Requirements

Users shall provide forecast peak day **Demand** profile (MW and power factor) and monthly peak **Demand** variations by time marked hourly throughout the peak day, net *of* the output profile of all **Generating Units** directly connected to a **User's Network** and not subject to

Central Dispatch. In addition **Users** shall advise of any sensitivity of **User Demand** to any voltage and frequency variations on the **Grid System;**

The maximum harmonic content which the **User** would expect its **Demand** to impose on the **Grid System;** and the average and maximum phase unbalance which the **User** would expect its **Demand** to impose on the **Grid System,** shall also be supplied.

PC A1.2.3 FLUCTUATING LOADS (> 1 MVA)

The following details are required by the GSSP Network Planner responsible for the **Network** to which the **User** is connected, or proposes to connect, concerning any fluctuating **Loads** in excess of 1 MVA:

(a) details of the cyclic variation of **Demand (Active** and **Reactive Power).**

(b) The rates of change of **Demand (Active** and **Reactive Power)** both increasing and decreasing;

(c) The shortest repetitive time interval between fluctuations in **Demand (Active** and **Reactive Power);**

(d) The magnitude of the largest step changes in **Demand (Active** and **Reactive Power)** both increasing and decreasing;

(e) Maximum **Energy** demanded per hour by the fluctuating **Demand** cycle; and

(f) Steady state residual **Demand (Active Power)** occurring between **Demand** fluctuations.

PC A1.2.4 User's Abnormal Loads

Details should be provided on any individual loads which have characteristics differing from the typical range of loads in domestic, commercial or industrial fields. In particular, details on arc furnaces, rolling mills, traction installations etc that are liable to cause flicker problems to other **Consumers.**

PC A1.3 GENERATING UNIT AND POWER STATION DATA

PC A1.3.1 GENERAL

All Generating Unit and **Power Station** data submitted to the GSSP Network Planner shall be in a form approved by the GSSP Network Planner. Where the **User** has undertaken modelling of the **Grid System** then the GSSP Network Planner should be advised of this and the results of the modelling including an electronic copy of the modelling data made available to the GSSP Network Planner. For the avoidance of doubt the **User** is not required under the PC to provide the modelling software to the GSSP Network Planner, unless it so chooses.

PC A1.3.2 Power Station Data Requirements

The data required relates to each point of connection to the **Grid System,** and shall include;

(a) the **Capacity** of **Power Station** in MW sent out for **Peak Capacity**, **Economic Capacity** and **Minimum Generation**; and

(b) maximum auxiliary **Demand (Active** and **Reactive Power)** made by the **Power Station** at start up and normal operation; and

(c) the operating regime of **Generating Units** not subject to **Central Dispatch.**

Where a **Generating Unit** connects to the **User's Network,** the output from this **Generating Unit** is to be taken into account by the **User** in its **Demand** profile submission to the GSSP Network Planner, except where such Generating Unit is subject to **Central Dispatch.** In the case where **Generating Unit** are not subject to **Central Dispatch,** the **User** must inform the GSSP Network Planner of the number of **Generating Units** together with their total **Capacity.** On receipt of such data, the User may be further required, at the GSSP Network Planner's discretion, to provide details of the **Generating Unit** together with their energy output profile.

PC A1.3.3 Generating Unit Data Requirements

The following parameters are required for each **Generating Unit** (which includes for the avoidance of doubt unconventional **Generating Units);**

(a) Prime mover type;

(b) **Generating Unit** type;

(c) **Generating Unit** rating and nominal voltage (MVA @ power factor & kV);

(d) **Generating Unit** rated power factor;

(e) **Economic Capacity** sent out (MW);

(f) **Maximum Continuous Rating** generation **(MCR)** and **Minimum Generation** capability sent out (MW);

(g) **Reactive Power** capability (both leading and lagging) at the lower voltage terminals of the generator transformers for **MCR** generation, **Economic Capacity** and minimum loading;

(h) Maximum auxiliary **Demand** in MW and Mvar;

(i) Inertia constant (MW sec/MVA);

(j) Short circuit ratio;

(k) Direct axis transient reactance;

(l) Direct axis sub-transient time constant;

(m) Generator transformer rated MVA positive sequence reactance and tap change rate;

(n) **Generating Unit** capability chart (example given in OC3 Appendix A).

PART 2

PC A2 DETAILED PLANNING DATA

PC A2.1 CONNECTION POINT AND USER NETWORK DATA

PC A2.1.1 General

All **Users** shall provide the appropriate GSSP Network Planner with the details as specified in PC A2.1.

PC A2.1.2 User Network Lay-out

Single line diagrams of existing and proposed arrangements of **Grid System** connection and primary **User Networks** including:

(a) Busbar layouts;

(b) Electrical circuitry (such as lines, cables, transformers, switch gear etc);

(c) Phasing arrangements;

(d) Earthing arrangements;

(e) Switching facilities and interlocking arrangements,

(f) Operating voltages; and

(g) Numbering and nomenclature.

PC A2.1.3 Reactive Compensation Equipment

For all independently switched reactive compensation equipment on the **User's Network** at **HV** and above, other than power factor correction equipment associated directly with the **User's Plant and Apparatus,** the following information is required:

(a) Type of equipment (for example, fixed or variable);

(b) Capacitive and or inductive rating or its operating range in Mvar;

(c) Details of automatic control logic, to enable operating characteristics to be determined by the GSSP Network Planner; and

(d) The point of connection to the **User's Network** in terms of electrical location and voltage.

PC A2.1.4 Short Circuit Infeed into the Transmission Network

Each **User** is required to provide the total short circuit infeeds, calculated in accordance with good industry practice, into the **TNSP Transmission Network** from its **User's System** at the Transmission Connection Point as follows:

(a) the maximum 3-phase short-circuit infeed including infeeds from any **Generating Unit** connected to the **User's System**;

(b) the additional maximum 3-phase short circuit infeed from any induction motors connected to the **User's Network;** and

(c) The minimum zero sequence impedance of the **User's System**.

PC A2.1.5 Lumped System Susceptance

Details of equivalent lumped network susceptance of the **User's System** at normal frequency at the transmission Connection Point. This should included any shunt reactors which are an integrated part of the cable network and which are not normally in or out of service independent of the cable. This should not include:

(a) independent reactive compensation plant on the **User's System;** or

(b) any susceptance of the **User's System** inherent in the **Active** and **Reactive Power Demand** data given under sub-section PC A2.2.

PC A2.1.6 Interconnector Impedance

For **User** interconnections that operate in parallel with the **Grid System** equivalent signal impedance (resistance, reactance and shunt susceptance) of the parallel **User** system. If the impedance is, in the reasonable opinion of the TSP Network Planner low, then more detailed information on the equivalent or active part of the parallel **User System** may be requested.

PC A2.1.7 Demand Transfer Capability

Where the same **Demand** may be supplied from alternative **Grid System** points of supply, the proportion of **Demand** normally fed from each **Grid System** point and the arrangements (manual and automatic) for transfer under planned or fault outage conditions shall be provided. Where the same **Demand** can be supplied from different **Users,** then this information should be provided by all parties.

PC A2.1.8 System Data

Each **User** with an existing or proposed **User Network** connected at **High Voltage** shall provide the following details relating to that **High Voltage Network:**

(a) Circuit parameters for all circuits:

(b) Rated Voltage (kV)

(c) Operating voltage (kV)

(d) Positive phase sequence reactance

(e) Positive phase sequence resistance

(f) Positive phase sequence susceptance

(g) Zero phase sequence reactance

(h) Zero phase sequence resistance

(i) Zero phase sequence susceptance

(j) Inter-bus transformers between the **User's High Voltage Network** and the **User's** main **Network**;

(k) Rated MVA

(l) Voltage ratio

(m) Winding arrangements

(n) Positive sequence reactance (max, min and nominal tap)

(o) Positive sequence resistance (max, min and nominal tap)

(p) Zero sequence reactance

(q) Tap changer range

(r) Tap change step size

(s) Tap changer type: on Load or off circuit

(t) Switchgear including circuit breakers, and disconnecters on all circuits connected to the Connection Point including those at **Power Stations**:

(u) Rated voltage (kV);

(v) Operating voltage (kV);

(w) Rated short-circuit breaking current, 3-phase (kA);

(x) Rated short-circuit breaking current, 1 -phase (kA);

(y) Rated load-breaking current, 3-phase (kA);

(z) Rated load-breaking current, I -phase (kA)

(aa) Rated short-circuit making current, 3-phase (kA); and

(bb) Rated short-circuit making current, 1-phase (kA)

PC A2.1.9 Protection Data

The information essential to the TNSP and/or DNSP Network Planner relates only to protection that can trip, intertrip or close any **Connection Point** circuit breaker or any **Grid System** circuit breaker. The following information is required:

(a) a full description, including estimated settings, for all relays and protection systems installed or to be installed on the **User's Network**;

(b) a full description of any auto-reclosing facilities installed or to be installed on the **User's Network**, 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 **Generating Unit,** generating unit transformer, station transformers and their associated connections;

(d) for **Generating Units** having (or intending to have) a circuit breaker on the circuit leading to the generator terminals, at the same voltage, clearance times for electrical faults within the **Generating Unit** zone; and

(e) The most probable fault clearance time for electrical faults on the **User's Network.**

PC A2.1.10 Earthing Arrangements

Full details of the system earthing on the **User's Network,** including impedance values.

PC A2.1.11 Transient Overvoltage Assessment Data

When undertaking insulation coordination studies, the TNSP and/or DNSP Network Planner will need to conduct overvoltage assessments. When requested by the appropriate Network Planner each **User** is required to submit estimates of the surge impedance parameters present and forecast of its **User Network** with respect to the **Connection Point** and to give details of the calculations carried out. The GSSP Network Planner may further request information on physical dimensions of electrical equipment and details of the specification of **Apparatus** directly connected to the **Connection Point** and its means of protection.

PC A2.2 DEMAND DATA

PC A2.2.1 General

All **Users** with demand shall provide the GSSP Network Planner with the **Demand** both current and forecast specified in this PC A2.2.

All forecast maximum **Demand** levels submitted to the GSSP Network Planner by **Users** shall be on the basis of average climatic conditions; and

So that the GSSP Network Planner is able to estimate the diversified total **Demand** at various times throughout the year, each User shall provide such additional forecast **Demand** data as the GSSP Network Planner may reasonable request.

PC A2.2.2 User's System Demand (Active and Reactive Power)

Forecast daily **Demand** profiles net of the output profile of all **Generating Units** directly connected to the **User's Network,** but not subject to **Central Dispatch,** by hours throughout the day as follows;

(a) peak **Demand** day on the **User's System;**

(b) day of peak **Grid System Demand (Active Power);** and

(c) day of minimum **Grid System Demand** (**Active Power**).

PC A2.2.3 User Consumer Demand Management Data

The potential reduction in **Demand** available from the **User** in MW and Mvar, the notice required to put such reduction into effect, the maximum acceptable duration of the reduction in hours and the permissible number of reductions per annum.

PC A2.3 GENERATING UNIT AND POWER STATION DATA

PC A2.3.1 General

All **Power Producers** with **Power Stations** which have a site rating **Capacity** of 5 MW and above shall provide the TNSP and/or DNSP Network Planner with details as specified in this PC A2.3.

PC A2.3.2 Auxiliary Demand

The normal unit-supplied auxiliary **Demand** is required for each **Generating Unit** at rated output MW; and the **Power Station** auxiliary **Demand,** if any, additional to the **Generating Unit Demand**, where the **Power Station** auxiliary **Demand** is supplied from the **Grid System,** is required for each Power Station.

PC A2.3.3 Generating Unit Parameters

The following parameters are requiring for each **Generating Unit;**

(a) Rated terminal voltage (kV);

(b) Rated MVA;

(c) Rated MW;

(d) Minimum Stable Generation (MW);

(e) Short circuit ratio;

(f) Direct axis synchronous reactance;

(g) Direct axis transient reactance;

(h) Direct axis sub-transient reactance;

(i) Direct axis transient time constant;

(j) Direct axis sub-transient time constant;

(k) Quadratrure axis synchronous reactance;

(l) Quadratrure axis transient reactance;

(m) Quadratrure axis sub-transient reactance;

(n) Quadratrure axis transient time constant;

(o) Quadratrure axis sub-transient time constant;

(p) Stator time constant;

(q) Stator resistance;

(r) Stator leakage reactance;

(s) Turbo generator inertial constant (MWsec/MVA);

(t) Rated field current; and

(u) Field current (amps) open circuit saturation curve for voltages at the generator terminals ranged from 50% to 120% of rated value in 10% steps as derived from appropriate manufacturer's test certificates.

PC A2.3.4 Parameters for Generator Unit Transformers

The following parameters are required for the generator unit transformer, or for the interbus transformer, where **Generating Units** connect to the **Grid System** through a transformer:

(a) Rated MVA with natural cooling and forced cooling;

(b) Voltage ratio;

(c) Positive sequence reactance (at max, min & nominal tap);

(d) Positive sequence resistance (at max, min & nominal tap);

(e) Zero phase sequence reactance;

(f) Tap changer range;

(g) Tap changer step size; and

(h) Tap changer type: on load or off circuit.

PC A2.3.5 Power Station Transformer Parameters

The following parameters are required for the **Power Station** interbus transformer where a **User** interbus transformer is used to connect the **Power Station** to the **Grid System**:

(a) Rated MVA with natural cooling and forced cooling;

(b) Voltage ratio; and

(c) Zero sequence reactance as seen from the higher voltage side.

PC A2.3.6 Excitation Control System Parameters

(a) DC gain of excitation loop;

(b) Rated field voltage;

(c) Minimum field voltage;

(d) Maximum field voltage,

(e) Maximum rate of change of field voltage (rising);

(f) Minimum rate of change of field voltage (falling);

(g) Details of excitation loop described in block diagram form showing transfer functions of individual terms;

(h) Dynamic characteristics of over-excitation limiter; and

(i) Dynamic characteristics of under-excitation limiter.

PC A2.3.7 Governor Parameters (for Reheat Steam Generating Unit)

The following parameters are required for a reheat steam **Generating Unit:**

(a) HIP governor average gain MW/Hz;

(b) Speeder motor setting rate;

(c) HIP governor valve time constant;

(d) HP governor valve opening limits;

(e) HIP governor valve rate limits;

(f) Reheater time constant (Active energy stored in reheater);

(g) IP governor average gain MW/Hz;

(h) IP governor setting range;

(i) IP governor valve time constant;

(j) IP governor valve opening limits;

(k) IP governor valve rate limits;

(l) Details of acceleration sensitive elements in HP & IP governor loop; and

(m) A governor block diagram showing transfer functions of individual elements.

PC A2.3.8 Governor Parameters (for non-Reheat Steam Generating Units and Gas Turbine Generating Units) including Generating Units within CCGT Blocks.

The following parameters are required for a heat recovery steam powered **Generating Unit** (without re-heat) and/or a gas turbine powered **Generating Unit:**

(a) Governor average gain;

(b) Speeder motor setting range;

(c) Time constant of steam or fuel governor valve;

(d) Governor valve opening limits;

(e) Governor valve rate limits;

(f) Time constant of turbine; and

(g) Governor block diagram.

PC A2.3.9 Governor and Associated Prime Mover Parameters - Hydro Generating Units

(a) Guide Vane Actuator Time Constant (in seconds);

(b) Guide Vane Opening Limits (%);

(c) Guide Vane Opening Rate Limits (%/second);

(d) Guide Vane Closing Rate Limits ((%/second); and

(e) Water Time Constant (in seconds).

PC A2.3.10 Plant Flexibility Performance

The following parameters are required for Generating Unit flexibility;

(a) Rate of **Loading** following weekend shutdown **(Generating Unit** and **Power Station);**

(b) Rate of **Loading** following an overnight shutdown **(Generating Unit** and **Power Station);**

(c) Block **Load** following **Synchronising;**

(d) Rate of de-**Loading** from normal rated MW;

(e) Regulating range; and

(f) **Load** rejection capability while still **Synchronised** and able to supply **Load.**

PC A2.4 ADDITIONAL DATA

PC A2.4.1 General

Notwithstanding the Standard Planning Data and Detailed Planning Data set out in this Appendix, the TNSP Network Planner and/or DNSP Network Planner may require additional data from **Users.** This will be to represent correctly the performance of **Plant** and **Apparatus** on the **Grid System** where the present data submissions would, in the TNSP Network Planner's or DNSP Network Planner's reasonable opinion, prove insufficient for the purpose of producing meaningful system studies for the relevant parties.

As the **GSO** is responsible for the overall coordination of the **Grid System,** then any data required by it will be requested through the relevant Network Planner. In addition, if the **Single Buyer** requires additional data then it will request such data through the **GSO** who will request data from a Network Planner if required to enable the **GSO** to answer the **Single Buyer.**

APPENDIX C TYPE OF STUDIES AND TESTS FOR MODEL VALIDATION

It is recommended that the following studies and tests in Table 7-B-1 should be considered for model validation. The measurements required are *P*, *Q*, V_{rms}, and I_{rms} at the output terminals of the inverter or at the grid connection point for several inverters. The voltage and current at the DC side of the inverter are also useful and should be measured in some tests.

- System dynamic response to control signal (small variation in control signals)
- System dynamic response to small disturbances in grid voltage
- Long-term voltage stability
- Short-term voltage stability
- FRT (Low/High/Zero voltage ride through)
- Short-circuit current contribution
- Rotor angle stability
- Solar radiation variation study
- Frequency instability study
- Unintentional islanding detection studies

It should be pointed out that not all the tests in Table 7-B-1 should be carried out in model validation. As a minimum, the model validation should be exercised for the studies it is designed for. For example, if a model of a PV converter is designed to represent the PV converter's anti-islanding protection, the model must be validated against the AI tests following the system requirements or according to the relevant standard such as IEEE 1547 in the US.

The IEC 61400-27-2 which describes the validation of the RMS model for power system dynamic studies can be referred to. It should be pointed out that this document is currently in voting stage.

Although Table 7-B-1 provides the detailed information for the required test, what the inverter can perform during testing very much depends on the control design of the inverter. That means, different inverters have different capabilities and performance. Such difference can be even significant. With the PV as primary energy source, this issue become even more system dependent. Therefore, it is noted that the figures in Table 7-B-1 come from limited experience and they could change.

Table 7-B-1: Type of studies and tests for model validation

Study Names	Tests to be Performed
System dynamic response to control signal (small variation in control signals)	Set the inverter operating in supporting grid mode, at an operation point, adjust the command of P within a small range, e.g. (-10%, +10%) monitor the time-trend of the defined measurements for comparison This test can be repeated a number of times at different operation points over the entire operation range
System dynamic response to small disturbances in grid voltage	Set the AC Grid at its nominal voltage, the inverter at a fixed operational mode (P/Q or P/V) and operate at its rated power, emulate a step change in the grid voltage in the range of (-10, +10%) of the nominal value monitor the time-trend of the defined measurements for comparison This test can be repeated a number of times with the inverter initially running at 0.2, 0.5, 0.8 and 1.0 p.u.
Long-term voltage stability *	Small voltage disturbance test: Select the inverter at a fixed operational mode (P/Q or P/V etc.), Test the system response to the grid voltage variation in the range of (-10, +10%) of the nominal value. Start the test with the inverter operating at its rated power level. Change the inverter operation point to a different value and repeat the test The test should cover the entire operation range of the inverter
1) Short-term voltage stability 2) FRT (Low/High/Zero voltage ride through) 3) Short-circuit current contribution	Large voltage disturbance tests Testing the voltage ride through capability Low voltage ride through test: with a fixed P, Q output, simulate the grid voltage dips for a specified duration. The depth (80% to 25% remaining voltage) and duration should be selected according to the standards that are applicable. In general, the duration is inversely proportional to the depth of the voltage dip, i.e. the lower the voltage dip, the shorter time the dip duration. Zero voltage ride through test: with a fixed P, Q output, simulating grid voltage dips down to very low level (15% to 5% remaining voltage) for a fixed duration, say 150ms. High voltage ride through test: with a fixed P, Q output, simulating the grid voltage rises for a specified duration. The magnitude and duration should be selected according to the standards that are applicable.
Rotor angle stability	Large frequency and voltage disturbance test with synchronous generators and long transmission lines: Do this at different operating points, simulate the Out Of Step (OOS) with acceleration of the synchronous generators. First swing OOS and multi-swing OOS should be represented.
Solar radiation variation study	Solar Irradiance disturbance test: start with operation at rated 1.0 pu power output, change the solar irradiance power input (PV cell output)**. Measurements: P, Q and V, I at the Grid connection point
Frequency instability study	Set the DC system operating at its 1.0 p.u. rated power level, Conduct a generator tripping or line tripping test which causes system separation: Do this at different operating point, simulating the frequency drop.
Unintentional islanding detection studies	Change the loading balance conditions. Change the type of loads, such as static load and induction motor load

*: Power flow based analysis for long-term voltage stability is out of scope.
**: It depends on geographic location, installation, PV panel and time and season variation.

Table 7.2 Type of studies and tests for model validation

Tests	Main features
System dynamic response to control signal	This test is to determine the dynamic response of the inverter system in response to a small change in control signal. The control signal can be either V_{ref} or Q_{ref}, or active power P or frequency f. The test is for checking the parameters like droop, deadband, control limit and range, the rise time, settling time and overshoot (if there is) in response. Set the inverter to the appropriate operation mode. In the tests for the response to P (or f), a variable prime energy source at the inverter DC side may be required, and the voltage and current at the inverter DC side should be monitored. Change the control signal in a small range, e.g. (-10%, +10%) Measure the time-trend of voltage, current, active and reactive power of the inverter.
System dynamic response to small disturbances in grid	This is a test of close-loop control function to the small variations. The test is to determine the dynamic characteristics of the inverter system in response to a change in the connected AC grid. The simulated variable represents the disturbance in the AC voltage or frequency. Set the inverter at an appropriate operational mode (P/V or P/Q); emulate a step change in the grid voltage, or a frequency change according to the AC system frequency characteristic; monitor the time-trend of the variables at the output of the inverter. This test should cover the sunny, cloudy and night conditions.
Long-term voltage stability	This is a test for validating the model that is designed for long-term voltage stability study by simulation in time-domain Analyse the AC grid long-term voltage stability at the inverter connection point. This covers the time duration from a few to several tens of seconds, and includes the effect of the load, tap changes, power plan control (AGC, excitation limit) and system operator action etc. Set the inverter at an appropriate operational mode (P/Q or P/V etc.); Emulate a change in the AC voltage that can cause an occurrence of a long-term voltage stability; monitor the time-trend of the variables at the output of the inverter. Repeat the test with different power input to the inverter at the DC side.
Short-term voltage stability. This includes FRT and short-circuit current contribution	It is a test for determining the inverter capabilities in response to the large voltage drop in the AC system and in the case of a short circuit. Set the inverter to an appropriate operation mode; Simulate the grid voltage dip for a specified duration. The depth of the dip is in the range of 80% to 25% of the remaining voltage. Duration should be defined according to the relevant standards. In general, the duration is inversely proportional to the depth of the voltage dip, i.e. the lower the voltage dip, the shorter the dip duration is. Monitor the parameters at the output of the inverter to determine its capability during the fault and in the recovery period. Simulate the grid voltage dips down to very low level in the range of 15% to 5% of the remaining voltage for a duration such as 150ms. In this case, the current from the inverter is the maximum current to the AC fault.

Tests	Main features
Rotor angle stability	This test is for determining the inverter response to the changes in frequency and voltage in a time scale from tens milliseconds to a few seconds. It works in the time phase when electro-mechanical interactions take place. The different systems can have very different transient behaviours. Analyse the AC grid transient rotor angle stability. This should include generator and motor dynamics, generator inertia, SVC, MSC and reactor control and DC system control. Simulate some credible fault events that can cause the generator Out-of-Step. Start at an appropriate operation condition, test the inverter response to the changes in the AC system when a single Out-of-Step and/or multiple Out-of-Step happens.
Solar radiation variation	This is the test for determining the operation range, protection and dynamic characteristics of the inverter in response to the change of input energy as prime energy source. The strength of the PV solar irradiance depends on geographic location, installation, PV panel and time and season variation. It can vary in a wide range from a few thousand W/m^2 to hundreds W/m^2 and even zero. Set the inverter operate in the energy delivery mode; Simulate the change of the input power at the inverter DC side in a similar pattern as the solar radiation variation Monitor the outputs of the inverters as well as the inputs of the inverter
Frequency instability	This test is for determining the inverter dynamic response to the large discrepancy from the nominal of the system frequency Analyse the grid frequency characteristics in the event of generator tripping or a line outage causing a large loss of demand. As the result the energy generation and demand become significant imbalance temporarily. The frequency change also depends on the system inertia. Simulation a tripping event that causes the AC frequency exceeding the LFSM level Monitor the inverter response to such an event
Unintentional islanding detection	This is the test to determine the inverter control capability in response to islanding. Depending on the way the inverter is connected, the inverter can operate in the f/V mode (the inverter feeds the island solely) or in the P/V mode (the inverter is in parallel with an AC line feeding the island). Strong fluctuations are expected when a part of the grid become an island. The induction motors and static loads can affect the frequency and voltage in the isolated part of the grid. The event can last from tens milliseconds up to hundred seconds Monitor the inverter response to the changes in frequency, voltage and power.

It should be pointed out that not all the tests in Table 7.2 should be carried out in model validation. As a minimum, the model validation should be exercised for the studies it is designed for.

Table 19 —Measurement data—type, points, sampling rate, retention and duration

Provision data type	Measurement/data points (as applicable)	Recording rate	Retention	Duration	Measurement (as applicable)
Plant SCADA data (CSV file)	The plant SCADA system is often a lower resolution repository of information that, at minimum, shall include the following data points: Measurements — *Point of measurement* voltage and medium-voltage *collector system* voltages — *Point of measurement* frequency — *IBR plant* active and reactive power output — *IBR units* active and reactive power output of individual[147] — Shunt dynamic device reactive power output Signals — External control signals from the *TS operator* (BA, RTO, RC, etc.) — External automatic generation control signals — Active and reactive power commands sent to *IBR units*	One record per s	1 year	One year	Table 7.1
Plant equipment status (tabular log file)	— All breaker statuses, including change of status log — Shunt (dynamic or static) reactive compensation device statuses — Substation transformer status (main step-up and *collector system*) — Status of on load tap changer — Medium-voltage *collector system* statuses — Status of individual *IBR units* — Time stamp — Time synchronization (e.g., GPS status word) or status of the GPS clock signal	Static, as changed	1 year	NA	Not applicable

[147] Variables like commands may be only recorded when the value is changed and not at a specified sampling rate.

Table 19—Measurement data—type, points, sampling rate, retention and duration *(continued)*

Provision data type	Measurement/data points (as applicable)	Recording rate	Retention	Duration	Measurement (as applicable)
Unit functional settings	— *IBR unit* autonomous functions parameter settings[148]	Static, as changed	1 year	NA	Not applicable
Sequence of events recording (SER) data (tabular log file, time tag shall have an accuracy of one millisecond or less)	SER devices should be sized to capture and store hundreds or thousands of event records and logs. SER event records can be triggered for many different reasons but at minimum, shall include the following: — Event date/time stamp (synchronized to common reference, e.g., Coordinated Universal Time [UTC]) — Event type (status changes, synchronization status, configuration change, etc.) — Sequence number (for potential overwriting)	Static, as changed	90 days	NA	Not applicable
Digital fault recording (DFR) data (COMTRADE format and tabular log file)	This data shall be captured for at least the plant-level (e.g., at the *point of measurement*) response to BPS events. It is typically high resolution (kHz) point-on-wave data (transient) and triggered based on configured settings. Data points shall include: — Time stamp — Phase-to-ground voltage for each phase — Bus frequency (as measured/calculated by the recording device) — Each phase current and residual or neutral current — Calculated active and reactive power output — If applicable, dynamic reactive device voltage, frequency, current, and power output — Applicable binary status	≥ 128 samples per cycle, triggered	90 days	5 s COMTRADE data, (split between pre-fault and post-fault data needs to be mutually agreed upon with the *TS owner/TS operator*)	Table 7.1

[148] For *IBR units* that use standardized settings specified in IEEE Std 1547-2018, the IEEE 1547.1/EPRI specified "Common File Format for DER Settings Exchange and Storage" [B18] may be used.

Table 19—Measurement data—type, points, sampling rate, retention and duration *(continued)*

Provision data type	Measurement/data points (as applicable)	Recording rate	Retention	Duration	Measurement (as applicable)
Dynamic disturbance recorder (DDR) data (COMTRADE format and tabular log file)	A DDR shall capture the specified plant-level data continuously at the *point of measurement*. This data can be used for multiple purposes including event analysis and disturbance-based model verification. Data points shall include: — Time stamp — Bus voltage phasor (phase quantities and positive-sequence) — Bus frequency — Current phasor (phase quantities and positive-sequence) — Calculated active and reactive power output	Input: ≥ 960 samples per s output: ≥ 60 times (records) per s, continuous[149]	1 year	NA[149]	Table 7.1
Inverter fault codes and dynamic recordings (CSV file and tabular log file)	For grid BPS faults/events which trigger ride-through operation of an *IBR unit* or cause it to trip, the following information shall be recorded at *IBR units* for analysis: — All major and minor fault codes — All fault and alarm status words — Change of operating mode — High- and low-voltage ride-through — High- and low-frequency ride-through — PLL loss of synchronism — DC current and voltage — AC phase currents and voltage — Pulse width modulation index (if applicable) — Control system command values, reference values, and feedback signals	Many kHz, triggered	90 days	5-s data, (split between pre-fault and post-fault data needs to be mutually agreed upon with the *TS owner/TS operator*)	Stated by *IBR owner*
Power quality—flicker (PQDIF format)	Plant-level P_{st} and P_{lt} using a flicker meter that is compliant with IEC 61000-4-15 and IEC 61000-4-30	10 min	90 days	NA	IEC 61000-4-30

[149] A DDR with continuous data recording and storage capability is required. However, if the *TS owner* allows a DDR which records based on triggers then triggered records shall be at least of 3 min. The record triggers (i.e., frequency, voltage etc.) shall be based on mutual agreement between the *TS owner* and the *IBR owner*.

Table 19—Measurement data—type, points, sampling rate, retention and duration *(continued)*

Provision data type	Measurement/data points (as applicable)	Recording rate	Retention	Duration	Measurement (as applicable)
Power quality—RVC (PQDIF format)	Plant-level RVC (DeltaV/V) using a PQ meter that is compliant with IEC 61000-4-30 (IEC RMS value measured by one cycle, updated every half cycle)	NA	90 days	NA	IEC 61000-4-30[150]
Power quality—Very short-term harmonics (COMTRADE or PQDIF format)	Plant level, both voltage and current harmonics as applicable (total distortion and individual harmonics up to order 50). Unless required by the *TS owner*, very short-term harmonics measurements are optional.	3 s	10 days	NA	IEC 61000-4-7 and IEC 61000-4-30
Power quality—short-term harmonics (COMTRADE or PQDIF format)	Plant level, both voltage and current harmonics as applicable (total distortion and individual harmonics up to order 50).	10 min	90 days	NA	IEC 61000-4-7 and IEC 61000-4-30
Power quality—long-term harmonics (COMTRADE or PQDIF format)	Plant level, both voltage and current harmonics as applicable (total distortion and individual harmonics up to order 50).	95 weekly percentile (per IEEE Std 519)	1 year	NA	IEC 61000-4-7 and IEC 61000-4-30

[150] The rapid voltage change algorithm should satisfy the requirements specified in IEC 61000-4-30:2015/AMD1:2021 or later.