भारतीय मानक

IS 18488 : 2024

Indian Standard

आई एस/आई ई सी 61850 पर आधारित उपस्थानकों का स्वचालन — मार्गदर्शिका

Substation Automation System Based on IS/IEC 61850 — Guidelines

ICS 33.200

भारतीय मानक ब्यूरो
BUREAU OF INDIAN STANDARDS
मानक भवन, 9 बहादुर शाह ज़फर मार्ग, नई दिल्ली - 110002
MANAK BHAVAN, 9 BAHADUR SHAH ZAFAR MARG
NEW DELHI - 110002
www.bis.gov.in www.standardsbis.in

February 2024 Price Group 9

Power Systems Relays Sectional Committee, ETD 35

FOREWORD

This Indian Standard was adopted by the Bureau of Indian Standards, after the draft finalized by the Power System Relays Sectional Committee had been approved by the Electrotechnical Division Council.

This standard provides guidelines for Substation Automation System (SAS) based on IS/IEC 61850 series of standards on communication networks and systems for power utility automation. The Substation Automation System (SAS) shall be installed to control and monitor all the sub-station equipment from remote control centres (RCC) as well as from local control centre.

The composition of the Committee responsible for formulation of this standard is given in Annex E.

For the purpose of deciding whether a particular requirement of this temporary standard is complied with, the final value, observed or calculated expressing the result of a test, shall be rounded off in accordance with IS 2 : 2022 'Rules for rounding of numerical values (*second revision*)'. The number of significant places retained in the rounded off value should be the same as that of the specified value in this standard.

Indian Standard

SUBSTATION AUTOMATION SYSTEM BASED ON IS/IEC 61850 — GUIDELINES

1 SCOPE

1.1 The substation automation system (SAS) shall be installed to control and monitor all the substation equipment from remote control centres (RCC) and remote control and supervision centre (RSCC), as well as from local control centre.

1.2 The SAS shall contain the following main functional parts:

a) Bay control unit (BCU) Intelligence electronic devices (IEDs) for control, interlocking, measurement and monitoring;

b) Merging units and switchgear controller IEDs (as applicable for process bus-based SAS only);

c) Redundant station human-machine interface (HMI) with industrial grade servers;

d) Redundant managed switched Ethernet local area network communication infrastructure with hot standby;

e) Redundant gateway for remote monitoring and control via industrial grade hardware (to RCC) through secured IEC 60870-5-104 protocol. Number of ports shall be as per requirement of RCC;

f) Redundant gateway for remote monitoring and control via industrial grade hardware (to RSCC), the gateway should be able to communicate with RSCC on IEC 60870-5-104 protocol;

g) DR/Engineering PCs, as specified;

h) Remote HMI and work station along with necessary printers, only if specified as requirement by the owner; and

j) Peripheral equipment like printers, display units, key boards, etc.

1.3 It shall enable local station control via a PC by means of human-machine interface (HMI) and control software package, which shall contain an extensive range of supervisory control and data acquisition (SCADA) functions.

1.4 It shall include communication gateway, intelligent electronic devices (IED) for bay control, protection and monitoring and inter IED communication infrastructure. An architecture drawing for SAS is enclosed at Annex B.

1.5 The communication gateway shall facilitate the information flow with remote control centres. The bay level intelligent electronic devices (IED) for protection and control shall provide the direct connection to the switchgear without the need of interposing components and perform control, protection, and monitoring functions. However, in case of process bus-based SAS, switchgear controllers (SGCs) shall be used as digital interfaces between switchgear and bay level IEDs. Suitable digital interface to be provided for other main equipment like transformers/reactors etc.

1.6 The substation automation system being offered shall generally conform to provisions of IEC 62351, IEEE 1686, IEC 62443 and/or other guidelines/ requirements as specified by the Government of India for cyber security.

1.7 Process bus-based SAS shall be applicable only if specifically required by the owner/purchaser.

2 REFERENCES

The standards listed below contain provisions, which, through reference in this text, constitute provisions of this standard. At the time of publication, the editions indicated were valid. All standards are subject to revision, and parties to agreements based on this standard are encouraged to investigate the possibility of applying the most recent editions of these standards.

3 TERMOLOGY

3.1 Attribute — Named element of data and of a specific type.

3.2 Back-up Protection — Protection which is intended to operate when a system fault is not cleared, or an abnormal condition is not detected within the required time either because of failure or inability of other protection to operate or failure of the appropriate circuit breaker(s) to trip.

3.3 Bay — A bay comprises of one circuit breaker and associated disconnectors, earth switches and instrument transformers.

3.4 Bay Control Unit (BCU) — Bay Level control IEDs for all bay level functions regarding control, monitoring (sometimes includes protection functions as well), inputs for status indication and outputs for commands.

3.5 Breaker Control Device (or Controller) — Control device for HV circuit breaker.

3.6 Busbars — In a substation, the busbar assembly necessary to make a common connection for several circuits.

3.7 CIM — In electric power transmission and distribution, the common information model (CIM), a standard developed by the electric power industry that has been officially adopted by the International Electrotechnical Commission (IEC), aims to allow application software to exchange information about the configuration and status of an electrical network.

3.8 Circuit Breaker — A mechanical switching device, capable of making, carrying and breaking currents under normal circuit conditions and also making, carrying for a specified time and breaking currents under abnormal circuit conditions such as those of short circuit.

3.9 Client — Entity that requests a service from a server, or which receives unsolicited data from a server.

3.10 Critical Assets — Facilities, systems and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the bulk electric system.

3.11 Cyber Assets — In a substation, they are the programmable electronic devices and communication networks including hardware, software, and data.

3.12 Critical Cyber Assets — Cyber Assets which are essential to the reliable operation of critical assets.

3.13 Dataset — Permits the grouping of data and data attributes. It is used for direct access and for reporting and logging. The attribute dataset shall identify a data-set that is contained in the logical-node.

3.14 Disconnector — A mechanical switching device which provides, in the open position, an isolating distance in accordance with specified requirements.

3.15 Ethernet — It is a family of computer networking technologies for local area networks (LANs) commercially introduced in 1980. Systems communicating over Ethernet divide a stream of data into individual packets called frames. Each frame contains source and destination addresses and error-checking data so that damaged data can be detected and retransmitted. The standards define several wiring and signalling variants.

3.16 Fault Clearance — The power system must be designed and operated to avoid instability, loss of synchronism, voltage collapse, undesired load shedding and unacceptable frequency and voltage. Good protection practices help meet these objectives by detecting and clearing faults rapidly. Rapid fault clearance helps to prevent severe power swings or system instability, minimize disruption of system, power transfer capability, prevent unreliable services, limit or prevent damage to equipment.

3.17 Fault Clearance Time — The time interval between the fault inception and the fault clearance.

3.18 Feeder Bay — In a substation, the bay relating to a feeder or a link to a transformer, a generator or another substation.

3.19 GOOSE — Generic Object-Oriented Substation Event (GOOSE) supports the exchange of a wide range of possible common data (digital and analogue) organized by a data-set.

3.20 Logical Node — Smallest part of a function that exchanges data. A logical node is an object defined by its data and methods.

3.21 Merging Unit — Interface unit that accepts multiple analogue current/voltage transformer and binary inputs and produces multiple time synchronized serial unidirectional multi-drop digital point to point outputs to provide data communication via the logical interfaces 4 and 5.

3.22 Multicast — Unidirectional, connectionless communication between a server and a selected set of clients. [IEC 61850-2].

3.23 Numeric Protection — A numeric protection performs analogue to digital conversion on samples of the secondary voltage and/or current signals and uses numerical methods to determine relay operation.

3.24 Peer-to-Peer— It is a communication model in which each party has the same capabilities and either party can initiate a communication session. Other models with which it might be contrasted include the client/server model and the master/slave model. In some cases, peer- to- peer communications is implemented by giving each communication node both server and client capabilities.

3.25 Process Bus — It is the communication bus between the primary equipment installed in the yard and the IEDs installed in the control room. The process layer of the substation is related to gathering information such as voltage, current and status information from the transformers and transducers connected to the primary power system process – the transmission of electricity. IS/IEC 61850 defines the collection of this data via two different protocol definitions, namely, unidirectional multi drop point-to-point fixed link carrying a fixed dataset and "configurable" dataset that can be transmitted on a multi-cast basis from one publisher to multiple subscribers.

3.26 Protected Zone — The portion of a power system protected by a given protection system or a part of that protection system. The boundary of the protected zone is defined by the position of the current transformers in order to identify the location of the fault. The position of the circuit breakers is chosen in order to facilitate the isolation of the fault.

3.27 Protection Equipment — Equipment incorporating one or more protection relays and, if necessary, logic elements intended to perform one or more specified protection functions.

NOTE — Protection equipment is part of a protection system.

3.28 Protection Relay — A measuring relay which, either solely or in a combination with other relays, is a constituent of protection equipment.

3.29 Redundancy — In an item, it is the existence of more than one means for performing a required function.

3.30 Substation Automation System — It provides automation within a substation and includes the IEDs and communication network infrastructure. [IEC 61850-1].

3.31 Sampled Analogue Value — IEC 61850-9-2 is used to transmit the signals (voltage, current as well as status information) from non-conventional or conventional instrument transformers to IEDs such as protective relays using a merging unit. The digitally formatted and time stamped multicast sampled analogue values are transmitted via fibre optic to IEDs.

3.32 Server — On a communication network, a functional node that provides data to, or that allows access to its resources by, other functional nodes. A server may also be a logical subdivision, which has independent control of its operation, within the software algorithm (and/or possibly hardware) structure. [IEC 61850-6]

3.33 Sampled Measured Value — *See* sampled analogue value (*see* **3.31**).

3.34 Station Bus — The station bus provides primary communications between the various logical nodes, which provide the various station protection, control, monitoring, and logging functions.

4 SYSTEM DESIGN

4.1 General System Design

The Substation automation system (SAS) shall be suitable for operating and monitoring the complete substation including the provisions of future extensions as specified in the instruction manual. IS/IEC 61850 and requirements of process bus level automation shall be clearly specified by the buyer/supplier at the time of order placement.

The systems shall be suitable for operation at extra high voltage substations, following the latest engineering practices, ensuring long-term compatibility requirements and continuity of equipment supply and the safety of the operating personnel.

The SAS shall support remote control and monitoring from remote control centres via gateways.

The operator interface shall be intuitive and designed in a way such that operating personnel shall be able to operate the system easily after receipt of basic training.

The system shall incorporate the control, interlocking, measurement, monitoring and specified protection functions, self-monitoring, signalling and testing facilities, measuring as well as memory functions, event recording and evaluation of disturbance recording. It shall also have provisions for inhibiting control on any or all devices for purpose of maintenance. The devices under maintenance shall be provided with tags which shall include provision for entering text as required. Metering/other devices having communication ports of other protocols may also be integrated into SAS using suitable protocol converter.

Self-monitoring of components, modules and communication shall be incorporated to increase the availability and the reliability of the equipment and minimize maintenance. Maintenance, modification or extension of components shall not cause a shutdown of the whole substation automation system.

IP addressing of the system shall be as per the IP plan provided by the supplier.

The system shall be remotely accessible for control, monitoring, operation and collection of disturbance records and shall be provided with a firewall/router to comply with the minimum requirements of IS 16335.

Bay level unit bay mimic along with relay and protection panels and DPC panels (to be described in technical specifications by the owner) in air-conditioned switchyard panel room suitably located in switchyard (GIS hall relay room in case of GIS substation) and station HMI in control room building for overall optimisation with respect to cabling and control room building.

In case of process bus-based SAS, both bay level unit and station bus level components maybe placed at a centralised location like control room.

4.2 System Architecture

The SAS shall be based on a decentralized architecture and on a concept of bay-oriented, distributed intelligence.

Functions shall be decentralized, object-oriented and located as close as possible to the process.

The main process information of the station shall be stored in distributed databases. The typical SAS architecture shall be structured in three levels, that is, process level, bay level and station level.

The process level (applicable, only in IS/IEC 61850 process bus-based SAS) is at the switchyard where instrument transformers, switchgear, transformers/ reactors are located, and employs IEC 61850-9-2 for communicating sampled measured values (SMV) to the bay level IEDs and GOOSE messaging for binary values exchange.

At bay level, the IEDs shall provide all bay level functions regarding control, monitoring and protection, inputs for status indication and outputs for commands. The bay level IEDs for protection and control shall provide direct connection to the switchgear without the need of interposing components and perform control, protection, and monitoring functions. However, in case of process bus-based SAS, switchgear controllers (SGCs) shall be used as digital interfaces between switchgear and bay level IEDs.

Each bay control IED shall be independent from each other and its functioning shall not be affected by any fault occurring in any of the other bay control units of the station.

The data exchange between the electronic devices on bay and station level shall take place via the communication infrastructure. This shall be realized using fibre-optic cables, thereby guaranteeing disturbance free communication. The fibre optic cables shall be run in G.I. conduit/HDPE pipes. Data exchange shall be realised using the protocols defined and standardized in the latest edition of IS/IEC 61850 with a redundant managed switched Ethernet communication infrastructure. The modelling of various aspects of substation automation system, like, data objects, data attributes, logical nodes, etc. shall be according to the latest edition of IS/IEC 61850.

The communication shall be made in fault-tolerant ring, excluding the links between individual bay IEDs to switch, wherein the redundant connections are generally not envisaged by the user/owner, such that failure of one set of fibre shall not affect the normal operation of the SAS. However, failure of fibre shall be alarmed in SAS. Each fibre optic cable shall have four spare fibres.

At station level, the entire station shall be controlled and supervised from the station HMI. It shall also be possible to control and monitor the bay from the bay level equipment at all times.

Clear control priorities shall prevent operation of a single switch at the same time from more than one of the various control levels, such as RCC, station HMI, bay level, and apparatus level. The priority shall always be on the lowest enabled control level.

The station level contains the station-oriented functions, which cannot be realised at bay level, for example, alarm list, event list related to the entire substation, or gateway for the communication with remote control centres.

The GPS time synchronising signal (as specified by the owner) for the synchronization of the entire system shall be provided.

The SAS shall contain the functional parts as described in **1.2**.

4.3 FUNCTIONAL REQUIREMENTS

The high-voltage apparatus within the station shall be operated from different places such as follows:

a) Remote control centres;
b) Station HMI; and
c) Local bay controller IED (in the bays).

Operation shall be possible by only one operator at a time with priority to the lowest enabled control level.

The operation shall depend on the conditions of other functions, such as interlocking, synchro-check, control-inhibit tags etc (*see* **5.1.1**).

4.3.1 *Selection before Execution*

For security reasons the command is always to be given in two stages – selection of the object and command for operation, under all modes of operation except emergency operation. Final execution shall take place only when selection and command are actuated.

4.3.2 *Command Supervision – Bay/Station Interlocking and Blocking*

Software Interlocking shall be provided to ensure that inadvertent or incorrect operation of switchgear causing damage and accidents in case of false operation can be avoided.

In addition to software interlocking, hardwired interlocking shall also be provided for:

a) Bus Earth switch Interlocking;

b) Transfer Bus interlocking (if applicable).

It shall be a simple layout, easy to test and simple to handle when upgrading the station with future bays. For software interlocking the SAS Supplier shall describe the scenario while an IED of another bay is either switched off or fails.

A software interlock override function shall be provided which can be enabled to bypass the interlocking function.

4.3.2 *Run Time Command Cancellation*

Command execution timer (configurable) must be available for each control level connection. If the control action is not completed within a specified time, the command should be cancelled and an alarm shall be generated to indicate the failure of command.

4.3.3 *Self-Supervision*

Continuous self-supervision function with a self-diagnostic feature shall be included. The redundant components such as servers, gateway shall monitor each other for availability and the active device shall takeover all the functions of the failed device. This failover shall happen within 30 seconds. The events occurring when a server is in failed state shall be synchronised from the active server.

5 SUBSTATION AUTOMATION SYSTEM: FUNCTIONS, FEATURES AND USER CONFIGURATION

The monitoring, control and configuration of all input and output logical signals and binary inputs, and relay outputs for all built-in functions and signals shall be possible both locally and remotely.

It shall also be possible to interconnect and derive input and output signals, logic functions, using built-in functions, complex voltage and currents, additional logics (AND gates, OR gates and timers). (Multi-activation of these additional functions shall be possible).

5.1 Bay Level Functions

In a decentralized architecture the functionality shall be as close to the process as possible. In this respect, the following functions can be allocated at bay level:

a) Bay control functions including data collection functionality in bay control/ protection unit; and

b) Bay protection functions.

Separate IEDs shall be provided for bay control function and bay protection function.

5.1.1 *Bay Control Functions*

5.1.1.1 *Overview of functions*

a) Control mode selection;

b) Select-before-execute principle;

c) Command supervision;

d) Interlocking and blocking;

e) Double command;

f) Synchro check, voltage selection;

g) Run time command cancellation;

h) Transformer tap changer control (raise and lower of tap) (for power transformer bays);

j) Transformer master/follower selection;

k) Operation counters for circuit breakers and pumps;

m) Hydraulic pump/air compressor runtime supervision;

n) Operating pressure supervision through digital contacts only;

p) m) Breaker position indication per phase;

q) Alarm annunciation;

r) Measurement display;

s) Local HMI (local guided, emergency mode);

t) Interface to the station HMI;

u) Data storage for at least 200 events;

v) Auto-reclose mode selection (non-auto/1-phase etc);

w) Protection transfer switch control (for transfer bus scheme arrangement);

y) Monitoring of gas tight chambers in gis;

z) Monitoring of temperature of transformer and reactor;

aa) Monitoring of multi gas output of transformer and reactor gas analyser;

bb) Switchgear position;

cc) PLCC counters;

dd) CSD status; and

ee) Any other requirement specified elsewhere in the specification.

5.1.1.2 *Control mode selection*

Bay level operation:

As soon as the operator receives the operation access at bay level, the operation is normally performed via the bay control IED. During normal operation bay control unit allows the safe operation of all switching devices via the bay control IED.

Emergency operation:

It shall be possible to close or open the selected Circuit Breaker with ON or OFF push buttons even during the outage of bay IED. All the interlocks shall be get bypassed under such circumstances.

Remote mode:

Control authority in this mode is given to a higher level (Remote Control Centre/Station HMI) and the installation can be controlled only remotely. Control operation from lower levels shall not be possible in this operating mode.

5.1.1.3 *Synchronism and energizing check*

The synchronism and energizing check functions shall be bay-oriented and distributed to the bay control and/or protection devices. These features are:

a) Settable voltage, phase angle, and frequency difference;
b) Energizing for dead line-live bus, live line-dead bus or dead line – dead bus with no synchro-check function; and
c) Synchronising between live line and live bus with synchro-check function.

5.1.1.4 *Voltage selection*

The voltages relevant for the Synchro check functions are dependent on the station topology, that is, on the positions of the circuit breakers and/or the isolators. The correct voltage for synchronizing and energizing is derived from the auxiliary switches of the circuit breakers, the isolator, and shall be selected automatically by the bay control and protection IEDs.

5.1.1.5 *Transformer tap changer control*

Digital RTCCs shall be integrated with the SAS to provide tap changer control functions. For conventional OLTC, tap raise/lower/monitoring function to be provided suitably through BCU or Protection IED.

5.1.1.6 *Auto-reclose mode selection*

Auto–reclose mode selection for each of the circuit breaker shall be facilitated through bay controller IED.

5.1.1.6 *Protection transfer switch control* (*As applicable*)

Based on selection of isolator for double main with transfer switching scheme or single main with transfer switching scheme for the switchyard, the protection shall be transferred automatically with an alarm indication that protection is successfully transferred.

5.1.1.7 *Monitoring of gas chambers in gis sub-stations*

In case of a GIS sub-stations, all the gas tight chambers are required to be monitored individually phase wise for their SF6 gas density status by the bay control unit in a bay. Sufficient number of inputs are required to be provided in the BCU. In case there is any limitation of number of inputs in the BCU, additional BCU are required to be provided as per requirement. These inputs shall be used for necessary monitoring, control and protection purpose.

5.1.2 *Bay protection functions*

5.1.2.1 *General*

The protection functions are independent of bay control function. The protection shall be provided by separate protection IEDs (numerical relays) and other protection devices as per specification of Protection system (to be specified separately by the Owner).

IEDs, shall be connected to the communication infrastructure for data sharing and meet the real-time communication requirements for automatic functions. The data presentation and the configuration of the various IEDs shall be compatible with the overall system communication and data exchange requirements.

5.1.2.2 *Event and disturbance recording function*

Each IED should contain an event recorder capable of storing at least 200 time-tagged events. Protection IED shall have built-in disturbance recorder function. Disturbance recorder as a standalone unit can also be specified by the owner, if required. Disturbance recorder shall be used to record the graphic form of instantaneous values of voltage and current in all three phases, open delta voltage and neutral current, open or closed position of relay contacts and circuit breakers including relay internal digital signals during the system disturbances or trip event. Detailed specification of disturbance recorder shall be separately specified by the owner. One set of evaluation software shall be supplied and loaded in disturbance recorder cum engineering work station (evaluation unit) and automatic downloading of disturbance files from IEDs to evaluation unit shall be done through station bus conforming to IEC 61850.

5.1.2.3 *Bay monitoring function*

Analogue inputs for voltage and current measurements shall be connected directly to the voltage transformers (VT) and the current transformers (CT) without intermediate transducers, or through merging units. The values of active power (W), reactive power (VAR), frequency (Hz), and the rms values for voltage (V) and current (I) shall be calculated in the Bay control/protection unit.

5.2 Station Level Functions

5.2.1 *Status Supervision*

The status of each switchgear, for example, circuit breaker, isolator, earthing switch, transformer tap changer, transformer/reactor temperature, transformer/reactor multi gas conditions, temperature of switchyard panel room, ambient temperature etc., shall be supervised continuously. Every detected change of status shall be immediately displayed in the single-line diagram on the station HMI screen, recorded in the event list, and a hard copy printout shall be produced. Alarms shall be initiated in the case of spontaneous status changes.

The switchgear status shall be indicated by two auxiliary switches, normally closed (NC) and normally open (NO), which shall give ambivalent signals. An alarm shall be initiated if these status indications are inconsistent or if the time required for operating mechanism to change status exceeds a predefined limit.

The SAS shall also monitor the status of sub-station auxiliaries. The status and control of auxiliaries shall be done through an additional one or more IED and all alarm and analogue values shall be monitored and recoded through this IED.

5.2.2 *Measurements*

The analogue values acquired/calculated in bay control/protection unit shall be displayed locally on the station HMI and in the remote-control centre. The abnormal values shall be discarded. The analogue values shall be updated based on the dead band settings and the same shall be demonstrated during FAT of the system.

Threshold limit values shall be configurable for alarm indications.

5.2.3 *Event and Alarm Handling*

Events and alarms are generated either by the switchgear, by the control IEDs, or by the station level unit. They shall be recorded in an event list in the station HMI. Alarms shall be recorded in a separate alarm list and appear on the screen. All, or a freely selectable group of events and alarms shall also be printed out on an event printer. The alarms and events shall be time-tagged with a time resolution of 1 ms. The tentative list for various feeders and systems are enclosed as Annex B.

5.2.4 *Station HMI*

5.2.4.1 *Substation HMI operation*

On the HMI the object shall be selected first. In case the blocking or interlocking conditions are not met, the selection shall not be possible and an appropriate alarm/annunciation/notification shall occur. If a selection is valid, the position indication will show the possible direction, and the appropriate control execution button shall be actuated in order to close or open the corresponding object.

Control operation from other places (for example, RCCs) shall not be possible in this operating mode.

5.2.4.2 *Presentation and dialogues*

The operator station HMI shall be redundant with hot standby and shall provide basic functions for supervision and control of the substation. The operator shall give commands to the switchgear on the screen manually.

The HMI shall give the operator, access to alarms and events displayed on the screen. Aside from these lists on the screen, there shall be a printout of alarms or events in an event log.

An acoustic alarm shall indicate abnormalities, and all unacknowledged alarms shall be accessible from the screen selected by the operator.

The following standard pictures shall be available from the HMI:

a) Dynamic Single-line diagram showing the switchgear status and measured values;

b) Control dialogues with interlocking or blocking information details. This control dialogue shall tell the operator whether the device operation is permitted or blocked and also show the Interlocking logic with status;

c) Measurement dialogues;

d) Alarm list, station/bay-oriented;

e) Event list, station/bay-oriented;

f) System status; and

g) Communication channel status.

5.2.4.3 *HMI design principles*

Consistent design principles shall be adopted with the HMI regarding the labels, colours, dialogues and fonts. Non-valid selections shall be dimmed out.

The object status shall be indicated using different status colours for:

a) Selected object under command;

b) Selected on the screen;

c) Not updated, obsolete values, not in use or not sampled;

d) Alarm or faulty state;

e) Warning or blocked;

f) Update blocked or manually updated;

g) Control blocked;

h) Normal state; and

j) Energised or de-energised state (based on substation topology).

5.2.4.4 *Process status displays and command procedures*

The process status of the substation in terms of actual values of currents, voltages, frequency, active and reactive powers as well as the status of circuit breakers, isolators and transformer tap-changers shall be displayed in the station single-line diagram.

In order to ensure a high degree of security against undesired operation, a "select-before-execute" command procedure shall be provided. After the "selection" of a switch, the operator shall be able to recognize the selected device on the screen, and all other switchgear shall be blocked. As communication between control centre and device to be controlled is established, the operator shall be prompted to confirm the control action and only then the final execute command shall be accepted**.** After the “execution” of the command, the operation switching symbol shall flash until the switch has reached its new position.

The operator shall be in a position to execute a command, only if the switch is not blocked and if no interlocking condition is going to be violated. The interlocking statements shall be checked by the interlocking scheme implemented at the bay and station levels.

After command execution, the operator shall receive a confirmation that the new switching position has been reached or an indication that the switching procedure was unsuccessful with the indication of the reason for non-functioning.

5.2.4.5 *System supervision and display*

The SAS system shall be comprehensively self-monitoring such that any faults are immediately indicated to the operator, possibly before they develop into serious situations. Such faults are recorded as a faulty status in a system supervision display. This display shall cover the status of the entire substation including all switchgear, IEDs, communication infrastructure and remote communication links, and printers at the station level, etc. Interlocking status of switchgear shall also be available for monitoring.

5.2.4.5 *Event list*

The event list shall contain events that are important for the control and monitoring of the substation.

The event and associated time (with 1 ms resolution) of its occurrence has to be displayed for each event.

The operator shall be able to call up the chronological event list on the monitor at any time for the whole substation or sections of it.

A printout of each display shall be possible on the hard copy printer.

The events shall be registered in a chronological event list in which the type of event and its time of occurrence are specified. It shall be possible to store all events in the computer for at least one month. The information shall also be accessible from a printed event log.

The chronological event list shall contain:

a) Position changes of circuit breakers, isolators and earthing devices;

b) Indication of protective relay operations;

c) Fault signals from the switchgear;

d) Switchgear local/remote status (as applicable);

e) Switchgear bypass position switch status (if applicable);

f) Indication when analogue measured values exceed upper and lower limits. Suitable provision shall be made in the system to define two level of alarm on either side of the value or which shall be user defined for each measured;

g) Loss of communication;

h) User actions (control/tag placement/ manual update) with user identity; and

j) System messages (operator logging info, System supervision and device monitoring, failure of supervisory control etc).

Filters for selection of a certain type or group of events shall be available. The filters shall be designed to enable viewing of events grouped per:

a) Date and time;
b) Bay;
c) Device;
d) Function for example, trips, protection operations etc; and
e) Alarm class;

5.2.4.6 *Alarm list*

Faults and errors occurring in the substation shall be listed in an alarm list and must be displayed in a flashing state along with an audible alarm. After acknowledgement of the alarm, it should appear in a steady (for example, not flashing) state and the audible alarm shall stop. The alarm should disappear only if the alarm condition has physically been cleared and the operator has reset the alarm with a reset command. The state of the alarms shall be shown in the alarm list (unacknowledged and persistent, unacknowledged and cleared, acknowledged and persistent).

Filters for selection of a certain type or group of alarms shall be available as defined for events.

In addition to the regular alarms, following alarms shall also be displayed and logged:

a) Alarms shall be displayed on the HMI, for each device of SAS when they lose time synchronization; and

b) 'GOOSE Fail Alarm' shall be configured which shall be generated when any of the subscriber IEDs fails to receive any of the GOOSE messages. These alarms shall be mapped IED-wise in the station HMI.

5.2.4.7 *Object picture*

When selecting an object such as a circuit breaker or isolator in the single-line diagram, the associated bay picture shall be presented first. In the selected object picture, all attributes like:

a) Type of blocking/control inhibit tag;

b) Authority;

c) Local/remote control mode;

d) RCC/SAS control; and

e) Errors, etc.

Shall be displayed.

5.2.4.8 *Control dialogues*

The operator shall give commands to the system by means of a mouse click on the single-line diagram. Data entry is performed with the keyboard. Dedicated control dialogues for controlling at least the following devices shall be available:

a) Breaker and disconnector;

b) Transformer tap-changer; and

c) Mode selection (L/R, Non-Auto/1-ph, auto/manual etc).

5.2.5 *User-authority Levels*

It shall be possible to restrict activation of the process pictures of each object (bays, apparatus...) within a certain user authorisation group. Each user shall then be given access rights to each group of objects, for example:

a) Display only;

b) Normal operation (for example, open/close of switchgear);

c) Restricted operation (for example, by-passed interlocking); and

d) System administrator.

For maintenance and engineering purposes of the station HMI, the following authorisation levels shall be available:

a) No engineering allowed;

b) Engineering/configuration allowed; and

c) Entire system management allowed.

The access rights shall be defined by passwords assigned during the log-in procedure. Only the system administrator shall be able to add/remove users and change access rights. In case of non-activity for a pre-determined period (say 30 minutes), the system will automatically log out the user and user has to log in again for doing any operation. Further each operation must be logged in, in the event/alarm list along with the user name.

5.2.6 *Reports*

The reports shall provide time-related follow-ups of measured and calculated values. The data displayed shall comprise:

a) Trend reports:

 1) Day (mean, peak);
 2) Month (mean, peak);
 3) Semi-annual (mean, peak); and
 4) Year (mean, peak).

b) Historical reports of selected analogue Values:

 1) Day (at 15 minutes interval);
 2) Week;
 3) Month; and
 4) Year.

It shall be possible to select stored values from the database in the process display on-line. Scrolling (for example, between days) shall be possible. Uncertain values shall be indicated. It shall be possible to select the time period for which the specific data are stored in the memory shall be displayed.

Following printouts shall be available from the printer and shall be printed on demand:

a) Daily voltage and frequency curves depicting time on X-axis and the appropriate parameters on the Y-axis. The time duration of the curve is 24 hours;

b) Weekly trend curves for real and derived analogue values;

c) Printouts of the maximum and minimum values and frequency of occurrence and duration of maximum and minimum values for each analogue parameter for each circuit in 24 hr period;

d) Provision shall be made for logging information about breaker status like number of operations with date and time indications along with the current vale it interrupts (in both condition for example, manual opening and fault tripping);

e) Equipment operation details shift wise and during 24 hours;

f) Printout on adjustable time period as well as on demand for MW, MVAR, current, voltage on each feeder and transformer as well as tap positions, temperature and status of pumps and fans for transformers;

g) Printout on adjustable time period as well as on demand system frequency and average frequency;

h) Reports in specified formats which shall be handed over to successful SAS Supplier. The SAS supplier has to develop these reports. The reports are limited to the formats for which data is available in the SAS database; and

j) It shall be possible to generate user made reports based on measured/recorded values of various combination of parameters particularly for transformer and reactors for the health of equipment depending upon defined criterion. This generation of reports must be user friendly and shall be easy to define.

All the utilities/tools used for building a report shall be provided with the system so that the owner is able to build new reports. The tools shall be user friendly with 'drag and drop' or 'menu-based selection' features and shall not require any knowledge of programming.

The reports utility shall be configured such that reports requiring long duration data (yearly) shall not take more than 2 minutes and this shall not impact the other applications running in the system.

5.2.7 *Trend Display (historical data)*

It shall be possible to illustrate all types of process data as trends - input and output data, binary and analogue data. The trends shall be displayed in graphical form as column or curve diagrams with a maximum of 10 trends per screen. Adjustable time span and scaling ranges must be provided.

It shall be possible to change the type of value logging (direct, mean, sum, or difference) on-line in the window. It shall also be possible to change the update intervals on-line in the picture as well as the select the threshold values for alarming purposes.

5.2.8 *Automatic Disturbance File Transfer*

All recorded data from the IEDs with integrated disturbance recorder as well as dedicated disturbance recording systems shall be automatically uploaded (event triggered and once per day in case no event during the day) to a dedicated computer and shall be stored on the hard disc in specified folders. Disturbance reports shall be accessible to the Remote-Control Centre also.

5.2.9 *Disturbance Analysis*

The PC based work station shall have necessary software to evaluate all the required information for proper fault analysis.

5.2.10 *IED Parameter Setting*

It shall be possible to access all protection and control IEDs for reading the parameters (settings) from the station HMI or from a dedicated monitoring computer. The setting of parameters or the activation of parameter sets shall only be accessible through a password.

5.2.11 *Automatic Sequences*

The available automatic sequences in the system shall be listed and described (for example, sequences related to the bus transfer in a GIS). It shall be possible for the operator to initiate pre-defined automatic sequences and also define new automatic sequences. The automatic sequencing is required to be developed at SCADA level.

5.3 Gateway

5.3.1 *Communication Interface*

The Substation Automation System shall have the capability to support simultaneous communications with multiple independent remote master stations, The Substation Automation System shall have communication ports on each gateway (two gateways per station) as follows:

a) Three ports for remote control centres on secure IEC 60870-5-104 protocol;

b) One port for regional system coordination centre (RSCC) as per IEC 60870-5-104; and

c) No. of additional ports shall be user specific.

The communication interface to the SAS shall allow scanning and control of defined points within the substation automation system independently for each control centre. The substation automation system shall simultaneously respond to independent scans and commands from owner's control centres (RCCs and RSCC). The substation automation system shall support the use of a different communication data exchange rate (bits per second), scanning cycle, and/or communication protocol to each remote-control centre. Also, each control centre's data scan and control commands may be different for different data points within the substation automation system's database.

The Gateway shall collect the IEC 61850 data directly from the IEDs through ethernet switches, without using any other intermediate interface or network device, and shall be implemented in a separate hardware, so that the failure of the local SCADA Server would not impact the remote communication through the Gateway.

The Gateway shall identify the actions performed by the each of the remote masters individually and log it in its database. The logs for last 30 days shall be stored and accessible at the Station HMI.

5.3.2 *Remote Control Centre Communication Interface*

Owner will supply communication channels between the substation automation system and the remote-control centre. The communication channels provided by owner will consist either of power line carrier, optical fibre, or leased line, the details of which shall be provided during detailed Engineering.

5.3.3 *Interface Equipment*

The Supplier shall provide interface equipment for communicating between substation automation system and remote-control centres and between substation automation system and regional system coordination centre. However, the communication channels available for this purpose shall be separately specified by the owner.

The communication interface with the RCCs is an Ethernet interface. In case of PLCC communication any modem supplied shall not require manual equalization and shall include self-test features such as manual mark/space keying, analogue loop-back, and digital loop-back. The modems shall provide for convenient adjustment of output level and receiver sensitivity. The modem should be stand-alone and complete in all respects including power supply to interface the SAS with the communication channel. The configuration of tones and speed shall be programmable and maintained in a non-volatile memory in the modem. All necessary hardware and software shall also be in the scope of SAS Supplier except the communication link along with communication equipment between substation control room and remote-control centre.

5.3.4 *Communication Protocol*

The communication protocol for gateway to the control centre must be open protocol and shall support IEC 60870-5-104 and IEC 61850 for all levels of communication for substation automation such as Bay to station HMI, bay to bay etc, based on the requirement specified. The protocol shall support the features such as Report by exception and periodic reporting so that the data update times at the RCC/RSCC can be optimised.

6 SYSTEM HARDWARE

6.1 General

Main components are redundant station HMI, remote HMI (remote HMI only if mentioned in by the owner as a requirement) and disturbance recorder work station.

The supplier shall provide redundant station HMI in hot standby mode. The servers used in these work stations shall be of industrial grade**.**

Redundant station HMI shall be capable to perform all functions for entire substation including future requirements as indicated in the SLD. It shall use industrial grade components. Processor and RAM shall be selected in such a manner that during normal operation not more than 30 percent capacity of processing and memory are used. Supplier shall demonstrate these features.

The capacity of hard disk shall be selected such that the following requirement should occupy less than 50 percent of disk space:

a) Storage of all analogue data (at 15 Minutes interval) and digital data including alarm, event list for two years and trend data for thirty (30) days;

b) Storage of all necessary software; and

c) 500 GB space for Owner's use.

Supplier shall demonstrate that the capacity of hard disk is sufficient to meet the above requirement.

6.1.1 HMI *(Human Machine Interface)*

The Visual Display Unit (VDU) shall show overview diagrams (Single Line Diagrams) and complete details of the switchgear with a colour display. All event and alarm annunciation shall be configurable in the form of lists. Operation shall be accessible by a user-friendly function keyboard and a cursor positioning device. The user interface shall be based on WINDOWS concepts with graphics and facility for panning, scrolling, zooming, decluttering etc. System shall be based on latest available version of operating software/Windows.

6.1.2 *Visual Display Units/*TFT's *(Thin Film Technology)*

The display units shall have high resolution and reflection protected picture screen. High stability of the picture geometry shall be ensured. The screen shall be at least "21" diagonally in size and capable of colour graphic displays.

The display shall accommodate resolution of 1280 X 1024 pixels or better.

6.1.3 *Printer*

It shall be robust and suitable for operation with a minimum of 132 characters per line. The printing operation shall be quiet with a noise level of less than 45 dB suitable for location in the control room. Printer shall accept and print all ASCII characters via master control computer unit interface.

The printer shall have an in-built testing facility. Failure of the printer shall be indicated in the station HMI. The printer shall have an offline mode selector switch to enable safe maintenance. The maintenance should be simple with provisions for ease of change of print head, ribbon changing, paper insertion etc.

All reports and graphics prints shall be printed on laser printer. One dot matrix printer shall be used exclusively for hourly log printing.

All printers shall be continuously online.

6.1.4 *Mass Storage Unit*

The mass storage unit shall be built-in to the station HMI. Measured values of all operations, and indications shall be stored in a mass-storage unit in form of DVD RW (a rewritable DVD disc). The unit should support at least Read (48X), Write (24X), and Re-Write (10X) operations, with multi-session capability. It should support IS 14176, Rock ridge and joliet file systems. It should support formatting and operation under the operating system provided for station HMI. The monthly back up of data shall be taken on disc. The data backup facility shall be inherent in the software**.**

6.1.5 *Switched Ethernet Communication Infrastructure*

The SAS supplier shall provide the redundant switched optical Ethernet communication infrastructure for SAS. One switch shall be provided to connect all IEDs in one diameter of each 765 kV and 400 kV yard and for two bays of 220 kV or below yard to communication infrastructure. Each switch shall have at least two spare ports for connecting bay level IEDs and one spare port for connecting the station bus.

The Ethernet Fast Switches shall be complied with IEC 61850. These Switches shall be suitable for the substation environment and shall conform to type tests as per IEC 61850-3.

6.1.6 *Firewall and Router*

There shall be two sets of Firewall and Routers which shall be connected to a LAN. This LAN shall be different than the IEC 61850 LAN. The substation firewall and router shall be suitable for the substation environment and shall comply with the requirements for IEC 61850-3.

The substation firewall shall have the following features:

a) IP firewall features such as address/port inspection and filtering;

b) be stateful firewall;

c) support upto four 10/100 Mbps fast Ethernet switches;

d) support IPv4 and IPv6;

e) have IP sec/VPN with 3DES/AES encryption;

f) have NAT;

g) have syslog capability;

h) be NERC compliant; and

j) have hot-standby operation with similar router.

The substation routers shall have the following features:

a) Routing protocols such as OSPF and support for IPv4 and IPv6;

b) 4 Ethernet interfaces of 10/100 Mbps;

c) 2 E1 interfaces;

d) Hot standby operation with a similar router;

e) Support IEEE 802.3u, 802.1p, 802.1Q, 802.1d, 802.1w; and

f) Traffic prioritization for routed IP flows/ports.

The substation firewall and router can be a single device.

6.2 Bay Level Unit or Bay Control Unit (BCU)

6.2.1 *General*

Bay Control Unit (BCU) shall be provided for each Bay (a bay comprises of one circuit breaker and associated disconnector, earth switches and instrument transformer, and the number of bays shall be as specified by the owner) for control and monitoring of the bay equipment. Separate BCU (as per specification) shall be provided for the monitoring of substation auxiliaries.

The BCUs shall have adequate capacity for the estimated hardwired Inputs and Outputs, and a minimum of two Inputs and outputs each as the spare capacity per BCU. Requirement for external IO modules shall be avoided as far as possible.

BCUs shall have redundant DC Power Supply or with automatic changeover scheme, to be fed from the two station DC power supplies. Each power supply shall be supervised separately and alarmed.

Each BCU shall be equipped with Local HMI (display) facilities, enabling control of each particular bay from BCU whenever required. The Local HMI facilities shall be provided/ availed by means of Graphical LCD display embedded into the front panel of the BCU. Display will show the SLD (with device identification number) showing status of bay switching equipment (such as circuit breaker, isolators, earth switches) and enabling actuation of switching controls. Other display type will be multiple displays of analog values readings/reports, displays for controls other than switching, alarm panel displays, diagnostic/on-line configuration displays etc.

In the event of switchgear apparatus controls, the software-interlocking scheme shall be applied based on hardwired analog/digital inputs or Process Bus signals. In the event of closing control for circuit breakers requiring the checking of synchronization conditions, software synchro-check scheme shall be applied as well. Auto-reclose functions mentioned elsewhere in the specification, if required, can also be applied.

6.2.2 *Design*

The bay unit shall use industrial grade components. The bay level unit, based on microprocessor technology, shall use numerical techniques for the calculation and evaluation of externally input analogue signals. They shall incorporate 'select-before-operate' control principles as safety measures for operation via the HMI. Following power interruption and/or communications failure, the BCU shall be able to restart automatically. Time synchronisation of BCUs with UTC time shall be done over the IEC 61850 field LAN for Substation with SAS. For conventional substation, time synchronisation of BCU shall be done by other suitable time synch input like IRIG-B, RS232 etc.

The bay units shall perform all bay related functions, such as control commands, bay interlocking, data acquisition, data storage, event recording and shall provide inputs for status indication and outputs for commands. The BCUs shall be directly connected to the switchgear. However, in case of Process Bus based SAS, Switchgear Controllers (SGCs)/Merging Units (MUs) shall be used as digital interfaces between switchgear/instrument transformers and bay level IEDs. The bay unit shall acquire and process all the data for the bay (Equipment status, fault indications, measured values, alarms etc) and transmit these to the other devices in sub-station automation system. In addition, it shall receive the operation commands from station HMI and control centre.

One Bay Control Unit shall be provided for supervision and control of each 765kV, 400kV, 220kV, 132 kV bay. The Bay level unit shall be equipped with analogue and binary inputs/outputs for handling the control, status monitoring and analogue measurement functions. All bay level interlocks are to be incorporated in the Bay level unit so as to permit control from the Bay level unit/local bay mimic panel, with all bay interlocks in place, during maintenance and commissioning or in case of contingencies when the station HMI is out of service. Bay control unit can also include supervision and control of more than one bay, if specified by the owner (for medium voltage level only).

The bay control unit to be provided for the bays shall be preferably installed in the CB relay panel/feeder protection panel for the respective bay. Further in case of one and half breaker schemes, the BCU for Tie Circuit Breaker shall be provided in Tie Circuit Breaker relay panel. The tie circuit breaker relay panel shall also house the Ethernet switch(es) to be provided for the diameter. The bay control unit for any future bay (if required by the owner) shall be installed in a separate panel.

The Bay level unit shall meet the requirements for withstanding electromagnetic interference according to relevant parts of IEC 61850. Failure of any single component within the equipment shall neither cause unwanted operation nor lead to a complete system breakdown.

6.2.3 *Input/ Output (I/O) Modules (applicable for non-Process Bus SAS)*

The I/O modules shall form a part of the Bay Level Unit / Bay Control Unit and shall provide coupling to the substation equipment. The I/O modules shall acquire all switchgear information (for example, data coming directly from the switchgear or from switchgear interlocking devices) and transmit commands for operation of the switchgear.

It shall be suitable for analog inputs from secondary of instrument transformers for example, CT and CVT/PT secondary output can be connected directly to the relay analog input terminal.

The BCU/IED shall be able to integrate at least 10 analog input channels and 10 digital input/output channel to meet the control and monitoring scheme requirement.

Plant alarms and indications will be derived as digital input. Plant contacts shall change state to register the specified status change or alarm, and each input shall be configurable to register a positive input from either a closed or open contact, for example, input signals may be either a normally open or a normally closed contact. Alarm contacts may be either fleeting or sustained inputs. Digital filtering to suppress plant contact bounce shall be provided for each input. Time tagging to a resolution of 1ms shall be provided.

The pulse counting inputs shall be provided as per scheme requirement. These inputs shall acquire and count impulses produced by potential free contacts, which can be either, normally open or normally closed. Pulse counting inputs shall be provided as either a separate input module or using digital inputs. These inputs shall meet the same requirements specified for digital inputs, additionally they shall be able to cater for pulse rates up to 10 per second.

Where DC analogue measurement inputs are provided as per the scheme requirement, they shall be capable of accepting unipolar and bipolar current of range 0 mA to 10/4 mA to 20 mA and - 10 mA to + 10 mA (range as applicable for the project), with over/under range detection.

The command outputs shall be designed to provide ‘select’ and ‘execute’ outputs. The period of the command pulse shall be configurable between 0.1 second and 15 seconds on point basis. The command pulses shall reset immediately after the command is executed. Controls transmitted between the operator workstation of SAS/SCADA and the BCU shall comprise a select, check back and execute sequence (or other means of providing high message security).

6.2.4 The BCU supplied for substation automation system shall further meet any additional requirements mentioned elsewhere in the specification.

6.3 Extendibility in Future

Offered substation automation system shall be suitable for extension in future for additional bays. In case of such requirement, all the drawings and configurations, alarm/event list etc displayed shall be designed in such a manner that its extension shall be easily performed by the owner. During such event, normal operation of the existing substation shall be unaffected and system shall not require a complete shutdown. The supplier shall provide all necessary software tools along with details to perform addition of bays in future and complete integration with SAS by the owner. These software tools shall be able to configure IED, add additional analogue variable, alarm list, event list, modify interlocking logics etc for additional bays/ equipment which shall be added in future.

Following is to be ensured during initial supply of system:

a) All the licenses for various components such as SCADA, servers, configuration tools for various IEDs, Gateways etc shall be for complete system for example, system as per single line diagram including both present and future scope. The supplier shall submit the list of equipment and Inputs/Outputs covered under the licences provided; and

b) All the servers shall be capable of handling total system (present and future).

In case of extension packages, the interoperability between devices compliant to IEC 61850 Edition 2 (or latest) and existing devices compliant to IEC 61850 Edition 1 should be ensured.

7 SOFTWARE STRUCTURE

The software package shall be structured according to the SAS architecture and strictly divided in various levels. Necessary firewall shall be provided at suitable points in software to protect the system. An extension of the station shall be possible with lowest possible efforts. Maintenance, modification or an extension of components of any feeder may not force a shut-down of the parts of the system which are not affected by the system adaptation.

7.1 Station Level Software

Human-Machine Interface (HMI)

The base HMI software package for the operator station shall include the main SAS functions and it shall be independent of project specific hardware version and operating system. It shall further include tools for picture editing, engineering and system configuration. The system shall be easy to use, to maintain, and to adapt according to specific user requirements. Systems shall contain a library with standard functions and applications.

7.2 Bay Level Software

7.2.1 *System Software*

The system software shall be structured in various levels. This software shall be placed in a non-volatile memory. The lowest level shall assure system performance and contain basic functions, which shall not be accessible by the application and maintenance engineer for modifications. The system shall support the generation of typical control macros and a process database for user specific data storage. In case of restoration of links after failure, the software along with hardware shall be capable of automatically synchronising with the remaining system without any manual interface. This shall be demonstrated by supplier during integrated system test.

7.2.2 *Application Software*

In order to ensure robust quality and reliable software functions, the main part of the application software shall consist of standard software modules built as functional block elements. The functional blocks shall be documented and thoroughly tested. They shall form part of a library.

The application software within the control/ protection devices shall be programmed in a functional block language.

7.3 Network Management System (NMS)

The supplier shall provide network management system software for following management functions:

a) Configuration Management;

b) Fault Management; and

c) Performance Monitoring.

This system shall be used for management of communication devices and other IEDs in the system. This NMS can be loaded in Disturbance Recorder (DR) work-station and shall be easy to use, user friendly and menu based. The NMS shall monitor all the devices in the SAS and report if there is any communication fault/problem in the monitored devices. The NMS shall:

a) Maintain performance, resource usage, and error statistics for all managed links and devices and present this information via displays, periodic reports and on demand reports;

b) Maintain a graphical display of SAS connectivity and device status;

c) Issue alarms when error conditions occur; and

d) Provide facility to add and delete addresses and links.

7.4 Operating System

The Operating system of the Servers, HMIs and Gateways shall be hardened in line with the following suggested guidelines to reduce its vulnerability to cyber-attacks.

7.4.1 *Secure Build Strategy*

Packages unnecessary for system operation shall not to be installed during the initial build of the servers and workstations, reducing the amount of post-build hardening required. Any package that must be installed but is not required to be actively running shall be disabled.

The software to be removed and/or disabled includes, but is not limited to:

a) Games;

b) Messaging services;

c) Servers or clients for unused Internet services;

d) Software compilers (except where required, for example, development platform);

e) Unused networking and communication protocols;

f) Unused operating system features; and

g) Free utilities delivered with OS.

7.4.2 *Generic and Default Accounts*

Disable or remove all unnecessary generic and default user accounts from the operating system and third-party applications. Application accounts (such as daemon) that exist strictly for identification and ownership shall be disabled from all interactive, network, or other access to prevent unauthorized access. Required accounts and their functions shall be documented.

7.4.3 *Insecure Protocol*

Insecure protocols such as telnet, FTP, RSH, and RCP shall be disabled from operation.

7.4.4 *Malicious Software Prevention*

Anti-virus and other malicious software prevention tools shall be implemented to detect, prevent, deter, and mitigate the introduction, exposure, and propagation of malware. Supplier shall verify that commercially available anti-malware products do not cause any harm to the product.

Procedures on how to update the signature database of the anti-malware software shall be provided, if required by supplier.

7.4.5 *System Whitelisting*

System whitelisting shall be done i.e. the software takes an inventory of the host in a known good state, and any applications not present at that time (such as viruses, malware, games, portable applications, etc) shall be prevented from executing.

7.4.6 *Ports and Services*

The system shall be configured by the supplier to only use those ports and services required for normal and emergency operations. The ports and services configured for operation shall be documented and supplied to the customer/owner as part of the deliverable system documentation.

7.4.7 *Host-Based Firewalls*

The host-based firewalls shall be configured with a standardized set of rules as an additional layer of security if the network firewalls were to fail. The host-based firewalls are configured with a default deny rule that logs any traffic not explicitly allowed.

In the case where a service cannot be disabled but does not require communication with hosts external to itself, this host-based firewall also serves to prevent any communication to the port(s) used by that service.

7.4.8 *Removable Media*

Removable media (CD and DVD, USB Drives, etc) is not required for the operation of the SAS and may be inhibited from operation, except in case of data back up on CD/DVD/SSD etc as per specification.

7.5 The supplier shall provide each software in two copies in CD/SSD/portable digital media to load into the system in case any problem related with Hardware/Communication etc occurs.

8 GENERAL GUIDELINES FOR IEC 61850 SAS ENGINEERING

a) Data exchange is to be realised using the protocols defined and standardized in the latest edition of IEC 61850 with a redundant managed switched Ethernet communication infrastructure. The modelling of various aspects of Substation automation system, like data objects, data attributes, logical nodes, etc shall be according to the latest edition of IEC 61850;

b) During the GOOSE communication engineering, it shall be ensured that the publishing IEDs shall have the quality attribute included invariably for each GOOSE message in the GOOSE dataset. Further, the subscriber IEDs shall not use any GOOSE message that it receives without the quality attribute;

c) The GOOSE subscribing IEDs shall have the feature of detecting duplicate GOOSE message and intrusion using State Number (StNum), Sequence Number (SqNum) fields of a GOOSE message;

d) Separate VLANs shall be created for multicast communication between IEDs belonging to different voltage levels. Also, a 'Cross-VLAN' shall be created which will include the IEDs of different voltage levels together as per the requirement of the cross communication for control/protection schemes;

e) A guideline over usage of logical nodes for Report Control/GOOSE control engineering shall be issued during the detailed engineering; and

f) In the control and protection schemes, wherever GOOSE messages are used, the schematic documents submitted by the supplier should indicate the communication between logical nodes (LNs) used in indicating the source and destination LNs.

9 ADDITIONAL REQUIREMENTS FOR IEC 61850 BASED PROCESS BUS PROJECTS (APPLICABLE ONLY IF PROCESS BUS SAS IS SPECIFIED BY THE OWNER)

9.1 Switchgear Controllers (SGC) IED

a) SGCs shall function as digital interface between switchgear and control and protection IEDs (bay level IEDs) and shall be installed near the switchgear in the switchyard;

b) SGCs shall be able to withstand the electrical and environmental conditions of the switchyard, like, temperature (preferably in the range of - 25 ˚C to 70 ˚C temperature), humidity (as specified by User/Owner), electromagnetic interference (EMI/EMC) conditions, radio interference etc. SGCs shall be installed in panels designed with IP55 protection (or better) for outdoor use. The SGCs shall be suitable for the hostile substation environment and shall comply with the requirements for IEC 61850-3;

c) Modelling of SGCs shall adhere to the IEC 61850 standard. Logical nodes, such as, XCBR and XSWI shall be used as the interfaces to Circuit Breaker and Isolator respectively. Engineering of the device shall comply with IEC 61850 Part 6 (substation configuration language). Further, to accommodate supervision inputs and other 4 mA to 20 mA (range as applicable for the project) inputs, logical nodes, as defined in the standard (the latest edition of IEC 61850) shall be used;

d) The devices shall use parallel redundancy protocol (PRP), and be high-availability Seamless Redundancy (HSR) capable as applicable to meet the SAS architecture requirement. SGC devices should be time synchronized via SNTP or IEEE 1588v2 (Precision Time Protocol – PTP). No separate cable shall be used for time synchronization purposes. Ethernet based Data Network which will be used for GOOSE communication shall also be used for time synchronization purposes;

e) The user shall be able to configure/access the device from the engineering PC in the control room;

f) The number of binary inputs and binary outputs along with 4 mA to 20 mA (range as applicable for the project) inputs shall be as per the requirement of the project. These mA inputs can either be provided in SGCs or can be provided in separate IEDs mounted near the equipment;

g) Each bay shall have at least one SGC; and

h) SGCs shall be powered by redundant station DC power supplies and if the same is not available, then external changeover circuit shall be used.

9.2 Merging Units (MU) for Conventional Current Transformer (CT) and Voltage Transformer (VT)

a) Merging Units (MU) shall digitize the conventional CT and VT values as per IEC 61850 Sampled Measured Values (SMV);

b) MUs shall be able to withstand the electrical and environmental conditions of the switchyard, like, temperature (preferably in the range of - 25 ˚C to 70 ˚C temperature), humidity (as specified by the owner/user), electromagnetic interference (EMI/EMC) conditions, radio interference etc. MUs shall be installed in panels designed with IP55 protection (or better) for outdoor use. The MU shall be suitable for the hostile substation environment and shall comply with the requirements for IEC 61850-3;

c) Modelling of MUs shall adhere to IEC 61850 standard. Logical nodes, such as, TCTR and TVTR shall be used as the interfaces to Current Transformer and Voltage Transformer respectively. Engineering of the device shall comply with IEC 61850 Part 6 (Substation Configuration Language);

d) The devices shall use parallel redundancy protocol (PRP), or/and high-availability Seamless Redundancy (HSR) capable as applicable to meet the SAS architecture requirement. Also, these devices should have the capability to be time synchronized via IEEE 1588v2 (precision time protocol — PTP). No separate cable is envisaged for time synchronization purposes. Ethernet based data network which will be used for SMV transmission shall also be used for time synchronization purposes;

e) The user shall be able to configure/access the device from a separate engineering PC in the control room;

f) Each bay shall have 2 MUs, each having CT and CVT inputs from different cores. For bus CVTs, separate MUs shall be provided; and

g) MUs should be powered from station DC power supplies, one from source-1 and other from source-2.

9.3 Specific Requirement for Control and Protection IEDs to be used in Process Bus SAS

a) The control and protection IEDs shall have 4 optical ports (2 each for connection with Process Bus LAN and Station Bus LAN). In case of insufficient availability of number of ports locally in the IED, then the Redundancy Boxes (Red Box) shall be used. However, at least 2 ports shall compulsorily be available localy on the IED (with one port having the capability to get connected with Process Bus LAN and other to get connected with Station Bus LAN);

b) The IEDs, wherever required, shall have the capability to internally summate the Sampled Values (SV) streams from two or more instrument transformers;

c) For Transformers and Reactors, sufficient (redundant) SGCs/MUs shall be provided in the Transformer/Reactor Marshaling Box (or in a separate panel near the Transformer/Reactor MB as per the site-specific conditions) for interfacing bushing CTs, Online DGA, PPM Monitor, Optical Temperature Sensor and other annunciation/data of Transformer/Reactor with the process bus/station bus of SAS;

d) Following alarms shall be generated by devices subscribing to SMV streams in the following two cases:

   1) When a subscribing IED stops receiving SMV streams from the Merging Unit(s), alarms shall be generated; and

   2) There shall be a mechanism in the IEDs to detect using the SMV streams, the loss of time synchronization of Merging Units.

In case, the IEDs are not receiving the Sampled Values or are receiving improper Sampled Values from the Merging Unit, the IEDs shall not process their functions which utilize those Sampled Values;

e) In addition to the requirements specified at **4.1.5** for Switched Ethernet Communication Infrastructure, the Ethernet Fast Switches shall be PRP (IEC 62439-3), HSR (IEC 62439-3) and PTP (IEEE 1588v2) capable;

f) A suggested architecture for Process bus based SAS is enclosed at Annex B. The architecture of process bus based SAS shall be such that the failure of any one ethernet switch or any one fibre section of the SAS LAN (either in process bus LAN or in station bus LAN) shall not result in any communication interruption; and

g) All the control and protection schemes/functions shall be designed and implemented with GOOSE messages and sampled values, unless specifically desired by OWNER to be implemented using hardwiring. For energy metering, hardwiring between CT and CVT and meters shall be done. For signal exchange between digital protection coupler (DPC) and protection IEDs and between CT/CVT and control switching devices (CSDs), hardwiring shall also be acceptable. For integration of analog and binary signals from station auxiliaries (DG, FFPH, air conditioning, AC and DC LT etc), hardwiring to IEDs shall also be acceptable.

10 TESTS

The substation automation system offered by the SAS Supplier shall be subjected to following tests to establish compliance with IEC 61850 for EHV sub-station equipment installed in sheltered area in the outdoor switchyard under specified ambient conditions.

10.1 Type Tests

10.1.1 *Control IEDs/BCU and Communication Equipment*

The above equipment shall confirm to following type tests as per IEC 61850-3:

a) Power input:
   1) Auxiliary voltage;
   2) Current circuits;
   3) Voltage circuits; and
   4) Indications.

c) Accuracy tests:
   1) Operational measured values;
   2) Currents;
   3) Voltages; and
   4) Time resolution.

d) Insulation tests:
   1) Dielectric tests; and
   2) Impulse voltage withstand test.

e) Influencing quantities:
   1) Limits of operation;
   2) Permissible ripples; and
   3) Interruption of input voltage.

f) Electromagnetic compatibility test:
   1) 1 MHZ. burst disturbance test;
   2) Electrostatic discharge test;
   3) Radiated electromagnetic field disturbance test;
   4) Electrical fast transient disturbance test;
   5) Conducted disturbances tests induced by radio frequency field;
   6) Magnetic field test;
   7) Emission (radio interference level) test; and
   8) Conducted interference test.

g) Function tests:
   1) Indication;
   2) Commands;
   3) Measured value acquisition; and
   4) Display indications.

g) Environmental tests:
   1) Cold temperature;
   2) Dry heat;
   3) Wet heat;
   4) Humidity (damp heat cycle);
   5) Vibration;
   6) Bump; and
   7) Shock.

10.1.2 All the IEDs and other communication equipment including Ethernet switches and SCADA/SAS software shall be compliant with the latest edition of IEC 61850 and should conform to conformance tests as per IEC 61850-10.

10.2 Factory Acceptance Tests

The supplier shall submit a test specification for factory acceptance test (FAT) and commissioning tests of the station automation system for approval based on the standard SAS FAT procedure of owner. Standard SAS FAT procedure shall be provided by owner during detail engineering for reference. For the individual bay level IEDs, applicable type test certificates shall be submitted.

The manufacturing and configuration phase of the SAS shall be concluded by the factory acceptance test (FAT). The purpose is to ensure that the supplier has interpreted the specified requirements correctly and that the FAT includes checking to the degree required by the user/owner. The general philosophy shall be to deliver a system on to the site only after it has been thoroughly tested and its specified performance has been verified, under site conditions as far as they can be simulated in a test lab. During FAT the entire sub-station automation system including complete control and protection system to be supplied under present scope shall be tested for complete functionality and configuration in factory itself. The extensive testing shall be carried out during FAT. The purpose of factory acceptance testing is to ensure trouble free installation at the site. No major configuration setting of system is envisaged at site.

The SAS Supplier shall provide the SCD file after FAT to the site so that any intermittent issues with FAT configuration and changed site configuration (if any) can be analysed.

If the complete system consists of parts from various suppliers or some parts are already installed on site, the FAT shall be limited to sub-system tests. In such a case, the complete system test shall be performed on site together with the site acceptance test (SAT).

In case of extension of sub-station, factory acceptance test shall be carried out with the help of a demo system owned by supplier. However, the complete system is to be tested along with SCADA at site by the supplier after complete integration of the system.

10.2.1 Hardware Integration Tests

The hardware integration test shall be performed on the specified systems to be used for Factory tests when the hardware has been installed in the factory. The operation of each item shall be verified as an integral part of system. Applicable hardware diagnostics shall be used to verify that each hardware component is completely operational and assembled into a configuration capable of supporting software integration and factory testing of the system. The equipment expansion capability shall also be verified during the hardware integration tests. The supplier specifically demonstrates how to add a device in future in SAS during FAT. The device shall be from a different manufacturer than the SAS supplier.

10.2.2 Integrated System Tests

Integrated system tests shall verify the stability of the hardware and the software. During the tests all functions shall run concurrently and all equipment shall operate for a continuous 100 hours period. The integrated system test shall ensure the SAS is free of improper interactions between software and hardware while the system is operating as a whole.

10.2.3 Site Acceptance Tests

The site acceptance tests (SAT) shall completely verify all the features of SAS hardware and software. The supplier shall submit the detailed SAT procedure and SAT procedure shall be read in conjunction with the specification.

11 SYSTEM OPERATION

11.1 Substation Operation

11.1.1 *Normal Operation*

Operation of the system by the operator from the remote RCC or at the substation shall take place via industry standard HMI (Human Machine interface) subsystem consisting of graphic colour VDU, a standard keyboard and a cursor positioning device (mouse).

The coloured screen shall be divided into 3 fields:

a) Message field with display of present time and date;

b) Display field for single line diagrams; and

c) Navigation bar with alarm/condition indication.

For display of alarm annunciation, lists of events etc a separate HMI View node shall be provided.

All operations shall be performed with mouse and/or a minimum number of function keys and cursor keys. The function keys shall have different meanings depending on the operation. The operator shall see the relevant meanings as function tests displayed in the command field (that is, operator prompting). For control actions, the switchgear (that is, circuit breaker etc) requested shall be selectable on the display by means of the cursor keys. The switching element selected shall then appear on the background that shall be flashing in a different colour.

The operator prompting shall distinguish between:

a) Prompting of indications for example, fault indications in the switchgear; and

b) Prompting of operational sequences for example, execution of switching operations.

The summary information displayed in the message field shall give a rapid display of alarm/message of the system in which a fault has occurred and alarm annunciation lists in which the fault is described more fully.

Each operational sequence shall be divided into single operation steps which are initiated by means of the function keys/window command by mouse. Operator prompting shall be designed in such a manner that only the permissible keys are available in the command field related to the specific operation step. Only those switching elements shall be accessible for which control actions are possible. If the operation step is rejected by the system, the operator prompting shall be supported by additional comments in the message field. The operation status shall be reset to the corresponding preceding step in the operation sequence by pressing one of the function keys. All operations shall be verified. Incorrect operations shall be indicated by comments in the message field and must not be executed.

12 POWER SUPPLY

Power for the substation automation system shall be derived from station DC power supplies. Inverter of suitable capacity shall be provided for station HMI disturbance recorder evaluation unit and its peripheral devices for example, printer etc. In the event of Power failure, necessary safeguard software shall be built for proper shutdown. Separate Inverters powered from separate station DC supplies shall be provided for main and hot standby SAS system accordingly. Separate inverter shall also be supplied for remote HMI and workstation only if only if requirement is specified by the owner/user.

13 DOCUMENTATIONS

The following documents shall be submitted for owner's approval during detailed engineering:

a) System architecture drawing;

b) Hardware specification;

c) Functional design document;

d) Clear procedure describing how to add an IED/bay/diameter in future covering all major suppliers; and

e) VLAN architecture drawing.

The following documentation to be provided for the system in the course of the project shall be consistent, CAD supported, and of similar look/feel. All CAD drawings shall be provided in DXF format:

a) List of drawings;

b) Substation automation system architecture;

c) Block diagram;

d) Guaranteed technical parameters, functional design specification and guaranteed availability and reliability;

e) Calculation for power supply dimensioning;

f) I/O Signal lists;

g) Schematic diagrams;

h) List of apparatus;

j) List of labels;

k) Logic diagram (hardware and software);

m) Switchyard panel room layout drawing;

n) Control room layout;

p) Test specification for factory acceptance test (FAT);

q) Test specification for site acceptance test (SAT);

r) The SCD files of the station's project shall be submitted by the supplier during the FAT and after successful commissioning of SAS;

s) A GOOSE matrix sheet with publisher and subscriber IEDs;

t) Product manuals (installation, configuration, maintenance, troubleshooting, detailed diagnostics etc);

u) Assembly drawing;

v) Operator's manual;

w) Complete documentation of implemented protocols between various elements;

y) Listing of applicable softwares in CD ROM; and

z) Other documents as may be required during detailed engineering.

Two sets of hard copy and four sets of CD ROM/USB drive containing all the 'as built' documents/drawings shall be provided.

14 TRAINING, SUPPORT SERVICES, MAINTENANCE AND SPARES

14.1 Training

The supplier shall arrange all hardware training platform required for successful training and understanding in India. The supplier shall provide all necessary training material. Each trainee shall receive individual copies of all technical manuals and all other documents required for training. These materials shall be sent to owner at least two months before the scheduled commencement of the particular training course. Class materials, including the documents sent before the training courses as well as class handouts, shall become the property of owner. Owner reserves the right to copy such materials, but for in-house training and use only. Hands-on training shall utilize equipment identical to that being supplied to the owner.

The schedule, location, and detailed contents of each course will be finalized during owner and supplier's discussions.

14.2 Computer System Hardware Course

A computer system hardware course shall be offered, but at the system level only. The training course shall be designed to give Owner's hardware personnel sufficient knowledge of the overall design and operation of the system so that they can correct obvious problems, configure the hardware, perform preventive maintenance, run diagnostic programs, and communicate with contract maintenance personnel. The following subjects shall be covered:

a) System hardware overview — Configuration of the system hardware;

b) Equipment maintenance — Basic theory of operation, maintenance techniques and diagnostic procedures for each element of the computer system, for example, processors, auxiliary memories, LANs, routers and printers. Configuration of all the system hardware equipment;

c) System expansion — Techniques and procedures to expand and add equipment such as loggers, monitors, and communication channels;

d) System maintenance — Theory of operation and maintenance of the redundant hardware configuration, failover hardware, configuration of the control panels, and failover switches. Maintenance of protective devices and power supplies;

e) Subsystem maintenance — Theory of design and operation, maintenance techniques and practices, diagnostic procedures, and (where applicable) expansion techniques and procedures. Classes shall include hands-on training for the specific subsystems that are part of owner's equipment or part of similarly designed and configured subsystems. All interfaces to the computing equipment shall be taught in detail; and

f) Operational training — Practical training on preventive and corrective maintenance of all equipment, including use of special tools and instruments. This training shall be provided on owner equipment, or on similarly configured systems.

14.2 Computer System Software Course

The supplier shall provide a computer system software course that covers the following subjects:

a) System programming — Including all applicable programming languages and all stand-alone service and utility packages provided with the system. An introduction to software architecture, Effect of tuning parameters (OS software, Network software, database software etc) on the performance of the system;

b) Operating system — Including the user aspects of the operating system, such as program loading and integrating procedures; scheduling, management, service, and utility functions; and system expansion techniques and procedures;

c) System Initialization and Failover — Including design, theory of operation, and practice;

d) Diagnostics — Including the execution of diagnostic procedures and the interpretation of diagnostic outputs;

e) Software documentation — Orientation in the organization and use of system software documentation; and

f) Hands-on training — It shall be conducted for a period of one week, with allocated computer time for trainee for performing unstructured exercises. The course instructor shall be available for assistance if necessary.

14.3 Application Software Course

The Supplier shall provide a comprehensive application software course covering all applications including the database and display building course. The training shall include:

a) Overview — Block diagrams of the application software and data flows; programming standards and program interface conventions;

b) Application functions — Functional capabilities, design, and major algorithms; associated maintenance and expansion techniques;

c) Software development — Techniques and conventions to be used for the preparation and integration of new software functions;

d) Software documentation — Orientation in the organization and use of functional and detailed design documentation; and programmer and user manuals; and

e) Hands-on training — It shall be conducted for a period of one week, with allocated computer time for trainee for performing unstructured exercises. The course instructor shall be available for assistance if necessary.

14.4 Requirement of training:

The supplier shall provide training for owner’s personnel comprehensively covering following courses:

Sl No.	*Name of Course*
(1)	(2)
i)	Computer system hardware
ii)	Computer system software
iii)	Application software

15 Maintenance

15.1 Maintenance Responsibility during the Guaranteed Availability Period

During guaranteed availability period, the supplier shall take continual actions to ensure the guaranteed availability and shall make available all the necessary resources such as specialist personnel, spare parts, tools, test devices etc. for replacement or repair of all defective parts and shall have prime responsibility for keeping the system operational. During guarantee period, supplier shall arrange visit of SAS manufacturer's representative to site as per requirement to review the performance of system. In case any defect and/or shortcoming is observed during the period, the same shall be attended by the supplier.

16 SPARES

16.1 Consumables

Consumables such as paper, cartridges shall be supplied by the supplier as specified by the user.

16.2 Mandatory Spares

All spares shall be supplied by the supplier as specified by the user based on the operational experience and failure rates over the life cycle. List of spares shall include at least one number of each type for all critical items like IEDs/Ethernet Switches/Patch cords etc.

16.3 Special Tools for IS/IEC 61850 based SAS

The supplier shall supply a GOOSE inspection and simulation tool. The tool(s) shall have the capability to sniff and inspect the GOOSE in the data network. The tool(s) shall also have the capability to extract the GOOSE information from .icd/.scd file(s) and simulate them.

For IS/IEC 61850 based Process Bus projects, the SAS supplier also shall supply a SV (IS/IEC 61850 Sampled Values) inspection and simulation tool. The tool(s) shall have the capability to sniff and inspect the SV in the data network. The tool(s) shall also have the capability to extract the SV information from .cid/.scd file(s) and simulate them.

17 LIST OF EQUIPMENTS

The quantity of following equipments shall be decided by SAS supplier in order to achieve guaranteed reliability and availability as declared:

a) Station HMI workstation;

b) Redundant station HMI (in hot-standby mode) workstation;

c) Bay level units along with bay mimic for number of bays as detailed by the user separately;

d) Bay level unit for auxiliary system (as per requirement);

e) Disturbance recorder work station (maintenance HMI);

f) Engineering PC for merging units (applicable in case of Process Bus projects);

g) Colour laser printer — 1 No. (for reports and disturbance records)

h) Dot matrix printers — (one for each alarm and log sheets);

j) All interface equipment for gateway to RCC and RSCC;

k) Communication infrastructure between bay level units, station HMI, printers, gateways, redundant LAN etc. as required;

k) Remote disturbance recorder workstation and remote HMI and along with one colour laser A4 printer (remote HMI, only if specified by user);

m) Modems as per requirement;

n) Routers — 2 nos.;

p) Merging units (MUs) [applicable for process bus SAS], as per requirement;

q) Switchgear controllers (SGCs) [applicable for process bus SAS], as per requirement;

r) Time synchronising equipment;

s) Power inverter, uninterrupted power supply (UPS) as per requirement; and

t) Any other equipment as necessary.

18 RELIABILITY AND AVAILABILITY

The SAS shall be designed to ensure that failure of any single component, processor, or device shall not render the system unavailable. The SAS shall be designed to satisfy the demands for reliability and availability concerning:

a) Mechanical and electrical design;

b) Security against electrical interference (EMI);

c) High quality components and boards;

d) Modular and tested hardware;

e) Thoroughly developed and tested modular software;

f) Easy-to-understand programming language for application programming;

g) Detailed graphical documentation and application software;

h) Built-in supervision and diagnostic functions;

j) Security

1) Experience of security requirements;

2) Process know-how;

3) Selection before execution at operation; and

4) Process status representation as double indications.

k) Distributed solution;

m) Independent units connected to the local area network;

n) Back-up functions;

p) Panel design suitable to the harsh electrical environment and ambient conditions;

q) Panel grounding, immune against transient ground potential rise; and

r) Auxiliary power fluctuations.

18.1 Guarantees Required

The availability for the complete SAS shall be guaranteed by the supplier. The supplier shall demonstrate the availability guaranteed by conducting the availability test on the complete sub-station automation system as a system after commissioning. The test shall verify the reliability and integrity of all sub-systems. Under these conditions, the test shall establish an overall availability of 99.98 percent. After the lapse of 1 000 h of cumulative test time, test records shall be examined to determine the conformance with availability criterion. In case of any outage during the availability test, the supplier shall rectify the problem and after rectification, the 1 000 h period shall re-start. If test objective is not met, the test shall continue until the specified availability is achieved.

The supplier shall establish the availability from the date of commencement of the availability test in three months.

The test completes successfully on compliance with the availability criterion. After the satisfactory performance, supplier and user shall mutually agree to the test results and guarantee shall become effective from that date.

ANNEX A

(*Clause* 2)

LIST OF REFERRED STANDARDS

IS No./Other Publication	*Title*
IS 14176 : 1994/ ISO 9660 : 1988	Information processing — Volume and file structure of CD-ROM for information interchange
IS 16335 : 2015	Power control systems — Security requirements
IEC 60870-5-101	Telecontrol equipment and systems — Part 5-101: Transmission protocols — Companion standard for basic telecontrol tasks
IEC 60870-5-104	Telecontrol equipment and systems — Part 5-104: Transmission protocols — Network access for IEC 60870-5-101 using standard transport profiles
IS/IEC/TR 61850-1 : 2013	Communication networks and systems for power utility automation: Part 1 Introduction and overview
IS/IEC/TS 61850-2 : 2019	Communication networks and systems for power utility automation: Part 2 Glossary
IS/IEC 61850-3 : 2013	Communication networks and systems for power utility automation: Part 3 General requirements
IS/IEC 61850-4 : 2020	Communication networks and systems for power utility automation: Part 4 System and project management
IS/IEC 61850-5 : 2013	Communication networks and systems for power utility automation: Part 5 Communication requirements for functions and device models
IEC 61850-6 : 2009 +AMD 1 : 2018 CSV	Configuration Communication networks and systems for power utility automation — Part 6: description language for communication in power utility automation systems related to IEDs
IEC 61850-9-2 : 2011	Communication networks and systems for power utility automation — Part 9-2: Specific communication service mapping (SCSM) — Sampled values over ISO/IEC 8802-3
IEC 61850-10 : 2012	Communication networks and systems for power utility automation — Part 10: Conformance testing
IS/IEC 62351 (all parts)	Power systems management and associated information exchange — Data and communications security
IS/IEC 62443 (all parts)	Security for industrial automation and control system
IEC 62439-3 : 2021	Industrial communication networks — High availability automation networks — Part 3: Parallel redundancy protocol (PRP) and high-availability seamless redundancy (HSR)
IEEE 1588 Version 2	Precision clock synchronization protocol for networked measurement and control systems

ANNEX B

(*Clauses* 1.4, 5.2 *and* 9.3)

LIST OF ANALOGUE AND DIGITAL INPUTS

B-1 MONITORING REQUIREMENTS

The basic monitoring requirements are specified as under:

a) Switchgear status indication;
b) Measurements (U, I, P, Q, f);
c) Event(s);
d) Alarm(s);
e) Oil and winding temperature of transformer and reactor individual units;
f) Ambient temperature;
g) Status and display of 415 V LT system, 220 V and 48 V DC system;
h) Status of display of fire protection system and air conditioning system;
j) Acquisitio of all counters in digital protection coupler (DPC) panels through potential free contacts from DPC or independently, by counting the receive/send commands;
k) Acquisition of alarm and fault record from protection relays;
m) Disturbance records;
n) Monitoring the state of batteries by displaying DC voltage, charging current and load current;
p) Tap-position of power transformer;
q) Temperature measured with optical temperature sensor (provided by transformer/reactor manufacturer);
r) Dissolved hydrogen/multi gas and moisture content monitor of transformer; and
s) Status and display of LT transformer and its associated switchgear for station auxiliary supply.

B-2 LIST OF INPUTS FOR BAYS

The inputs mentioned in **B-2.1** and **B-2.2** indicative and are not exhaustive. The exact number and description of digital inputs shall be prepared as per detailed engineering requirement. Along with the mentioned digital inputs at **B-2.2**, minimum of 200 inputs shall be kept spare for employer’s/owner’s use (for meeting any future scheme requirements). For extension of existing substations, minimum 04 no. digital inputs per bay shall be kept spare for future use.

B-2.1 Analogue Inputs

The list of analogue inputs for bays is as under:

SI No. (1)	*Bay Parameter Measurement Location* (2)	*Analogue Inputs* (3)
i)	For each line	a) Current 1) R phase 2) Y phase 3) B phase b) Voltage 1) R-Y phase 2) Y-B phase 3) B-R phase
ii)	For each transformer/reactor	a) Current 1) R phase 2) Y phase 3) B phase b) WTI (Winding wise) c) OTI d) Multigas DGA parameters e) Tap position (for transformer only)

Sl No. (1)	*Bay Parameter Measurement Location* (2)	*Analogue Inputs* (3)
iii)	For TBC and bus coupler	a) Current 1) R phase 2) Y phase 3) B phase
iv)	Common parameters	a) Voltage for Bus-I, Bus-II and transfer bus (wherever applicable) 1) R-Y phase 2) Y-B phase 3) B-R phase b) Frequency for Bus-I and Bus-II c) Ambient temperature of switchyard d) LT System 1) Voltage of main switch board section-I i) R-Y phase ii) Y-B phase iii) B-R phase 2) Voltage of main switch board section-II i) R-Y phase ii) Y-B phase iii) B-R phase 3) Current from LT transformer-I 4) Current from LT transformer-II 5) Current from diesel generator 6) Voltage of 220 V DCDB-I 7) Voltage of 220 V DCDB-II 8) Current from 220 V battery set-I 9) Current from 220 V battery set-II 10) Current from 220 V battery charger-I 11) Current from 220 V battery charger-I 12) Voltage of 48 V DCDB-I 13) Voltage of 48 V DCDB-II 14) Current from 48 V battery set-I 15) Current from 48 V battery set-II 16) Current from 48 V battery charger-I 17) Current from 48 V battery charger-II

B-2.2 Digital Inputs

The list of digital inputs for bays is as under:

Sl No. (1)	*Bay/System Parameter Measurement Location* (2)	*Digital Inputs* (3)
i)	Line bays	a) Status of each pole of CB b) Status of isolator and earth switch c) CB trouble d) CB operation/closing lockout e) Pole discrepancy operated f) Trip coil faulty g) LBB operated h) Bus bar protection trip relay operated j) Main breaker auto recloser operated k) Tie/transfer auto recloser operated m) Auto reclosure lockout n) Tie/transfer breaker auto reclosure lockout p) Direct trip - I/II sent q) Direct trip - I/II received r) Main I/II blocking s) Main I/II-Inter trip send t) Main I/II-Inter trip received u) Over-voltage stage – I operated v) Over-voltage stage – II operated w) Fault locator faulty y) Main-I/II CVT fuse fail z) Main-I protection trip aa) Main-II protection trip bb) Main-I PSB alarm cc) Main-I SOTF trip dd) Main-I R-phase trip ee) Main-I Y- phase trip ff) Main-I B- phase trip gg) Main-I start hh) Main-I/II carrier aided trip jj) Main-I/II fault in reverse direction kk) Main-I/II Zone-2 trip mm) Main-I/II Zone-3 trip nn) Main-I/II Weak end infeed operated pp) Main-II PSB alarm qq) Main-II SOTF trip rr) Main-II R-phase trip ss) Main-II Y-phase trip tt) Main-II B-phase trip uu) Main-II start vv) Main-II aided trip ww) Main-I/II fault in reverse direction yy) Back-up O/C operated zz) Back-up E/F operated aaa) 220V DC-I/II source fail bbb) Speech channel fail ccc) DPC protection Channel-I fail ddd) DPC protection Channel-II fail
ii)	Transformer bays (HV side)	a) Status of each pole of CB b) Status of isolator and earth switch

Sl No. (1)	*Bay/System Parameter Measurement Location* (2)	*Digital Inputs* (3)
		c) CB trouble d) CB operation/closing lockout e) Pole discrepancy opted f) Trip coil faulty g) LBB operated h) Bus bar protection trip relay opted j) REF operated k) Differential operated (phase wise) m) Overflux alarm (medium voltage) n) Overflux trip (medium voltage) p) Overflux alarm (high voltage) q) Overflux trip (HV) r) HV bus CVT ½ fuse fail s) MV bus CVT ½ fuse fail t) OTI alarm/trip u) PRD operated (each PRD) v) Overload alarm w) Bucholz trip y) Bucholz alarm z) OLTC buchholz alarm aa) OLTC buchholz trip bb) Oil low alarm cc) Back-up O/C (HV) operated dd) Back-up E/F (HV) operated ee) 220V DC-I/II source fail ff) Tap mismatch gg) GR-A protection operated hh) GR-B protection operated jj) Back-up O/C (MV) operated kk) Back-up E/F (MV) operated mm) Healthiness of each protection relay through watchdog contact.
iii)	Transformer bays (MV Side)	a) Status of each pole of CB, isolator and earth switch b) CB trouble c) CB operation/closing lockout d) Pole discrepancy operated e) Trip coil faulty f) LBB operated g) Bus bar protection trip relay operated h) Back-up impedance relay j) 220 V DC-I/II source fail k) GR-A Protection operated m) GR-B Protection operated
iv)	Line/bus reactor bays (as applicable)	a) Status of each pole of CB, isolator and earth switch b) CB trouble c) CB operation/closing lockout d) Pole discrepancy operated e) Trip coil faulty f) LBB operated g) Bus bar protection trip relay operated h) REF operated j) DIF operated (phase wise) k) Line/bus CVT ½ fuse fail m) OTI alarm/trip

SI No. (1)	*Bay/System Parameter Measurement Location* (2)	*Digital Inputs* (3)
		n) PRD operated p) Buchholz trip q) Buchholz alarm r) Oil low alarm s) Back-up impedance relay t) 220V DC-I/II source fail u) GR-A protection operated v) GR-B protection operated
v)	Bus bar protection	a) Bus bar Main-I Trip b) Bus bar Main-II Trip c) Bus bar Zone-I CT open d) Bus bar Zone-II CT open e) Bus transfer CT Supervision operated f) Bus transfer bus bar protection operated g) Bus protection relay fail
vi)	Auxiliary system	a) Incomer-I status (on/off) b) Incomer-II status (on/off) c) 415V Bus-I/II U/V d) 415V Bus coupler breaker on/off e) DG set breaker on/off f) Alarm/trip signals for DG set g) LT transformer-I buchholz alarm and trip h) LT transformer-II buchholz alarm and trip j) LT transformer-I WTI Alarm and trip k) LT transformer-II WTI Alarm and trip m) LT transformer-I OTI Alarm and trip n) LT transformer-II OTI Alarm and trip p) Exchange fail q) Time synchronization signal absent r) Alarm/trip signals for battery and battery charger s) 220V DC-I earth fault t) 220V DC-II earth fault u) Alarm/trip signals for fire protection system
vii)	Switchyard panel room	a) Air conditioner compressor 1 status (on/off) b) Air conditioner compressor 2 status (on/off) c) Fire Detection 1 status (on/off) d) Fire Detection 2 status (on/off) e) Switchyard panel room temperature high alarm

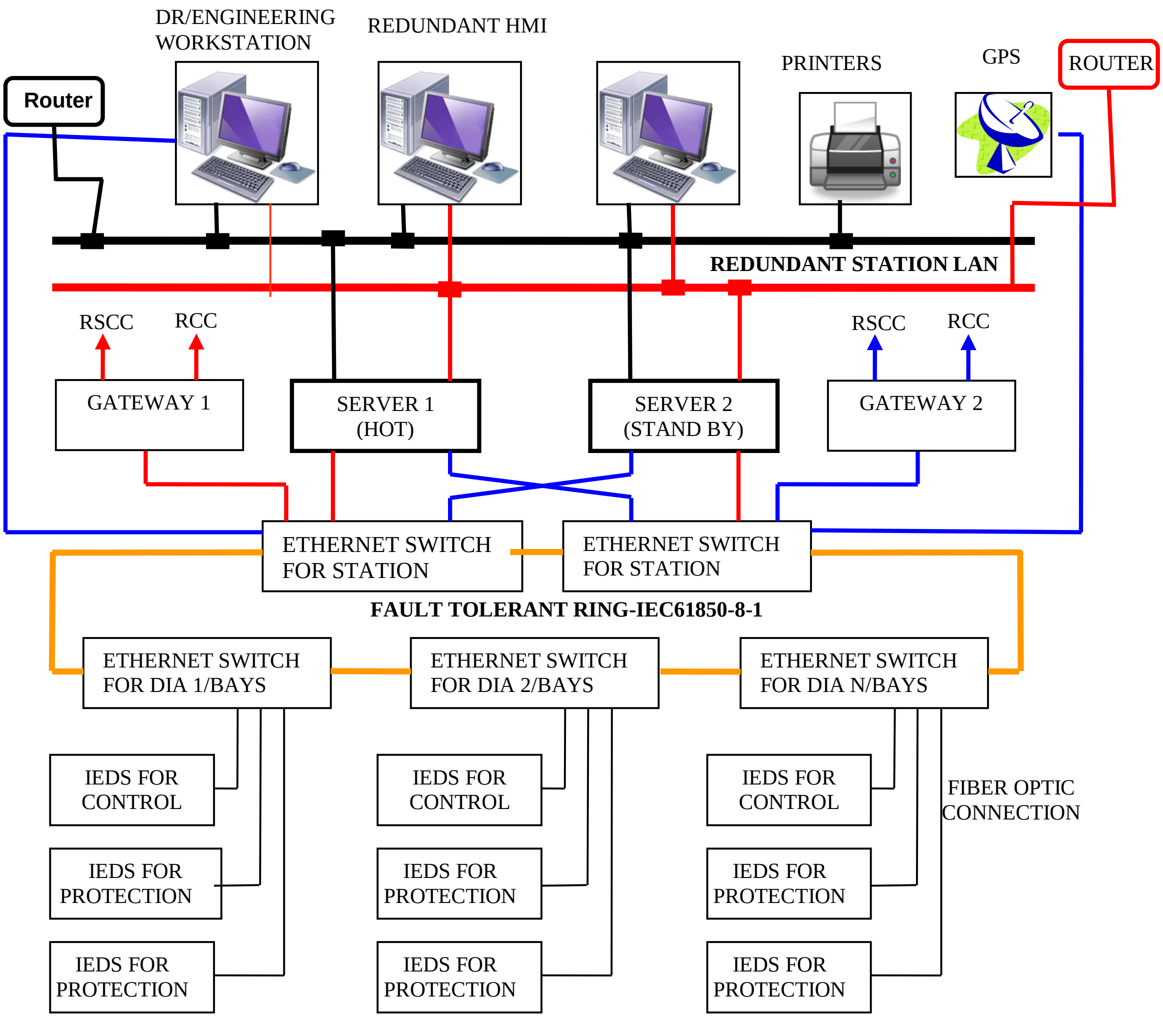

FIG. 1 TYPICAL ARCHITECTURAL DRAWING OF SUBSTATION AUTOMATION SYSTEM (WITHOUT PROCESS BUS)

NOTES

1 The redundant managed bus (station LAN) shall be realized by high speed optical bus using industrial grade components and shall be as per IEC 61850.

2 Inside the sub-station, all connections shall be realized as per IEC 61850 protocol.

3 For gateway, it shall communicate with Remote Supervisory Control Centre (RSCC) on IEC 60870-104 protocol. The number of ports required shall be as per **1.1** and **3.3**

4 The printer as required shall be connected to station bus directly and can be managed either from station HMI, HMI view node or disturbance recorder work station.

5 The above architectural layout is indicative and shall be suitably modified as per specific project requirement.

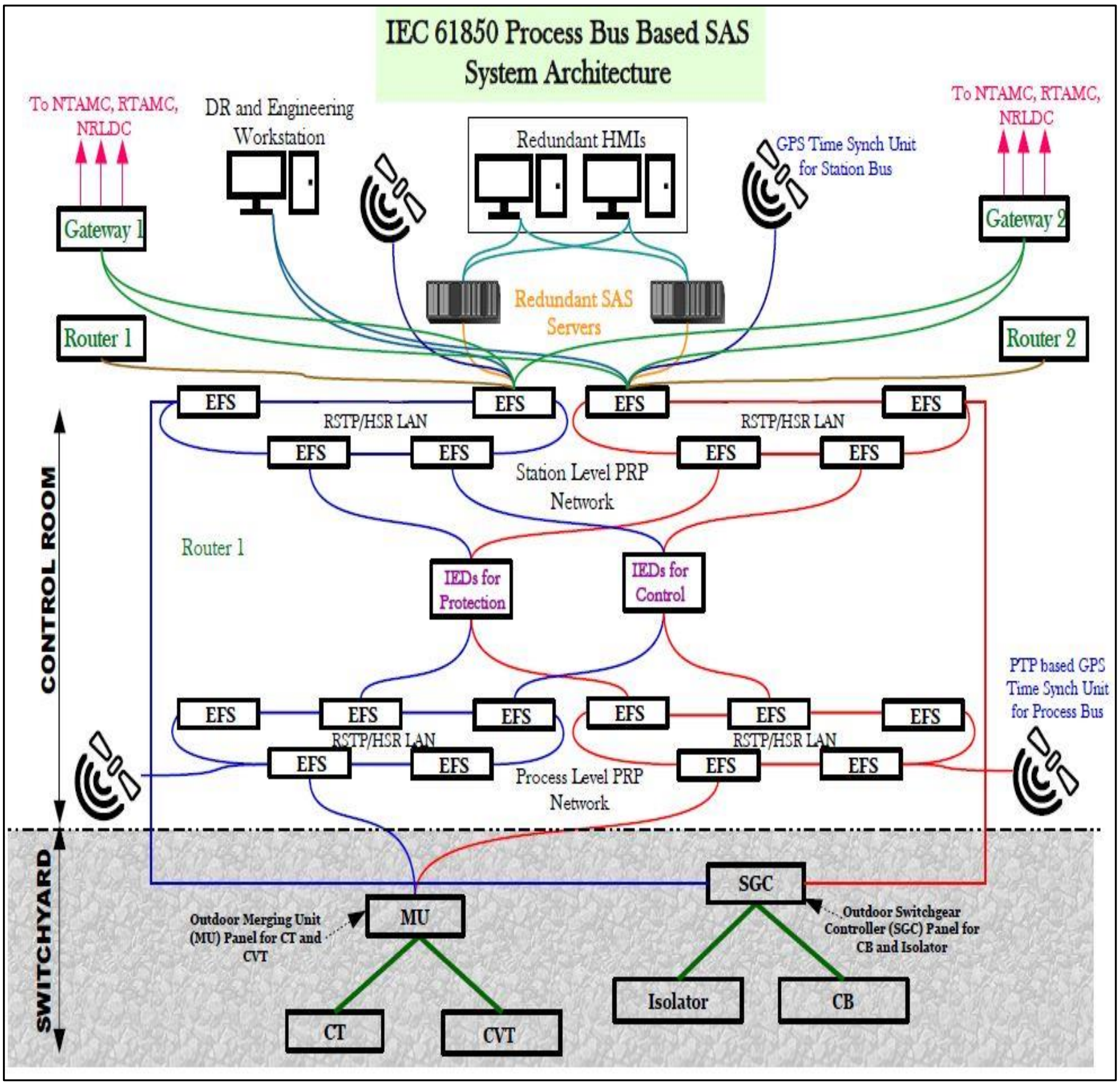

FIG. 2 TYPICAL ARCHITECTURAL DRAWING OF SUBSTATION AUTOMATION SYSTEM (WITH PROCESS BUS)

ANNEX C

LIST OF I/O POINTS TO BE TRANSMITTED TO RSCC

C-1 GENERAL

The list of input/output points to be transmitted to remote control and supervision centre (RSCC) is as under:

a) MW and MVAR for all lines, transformers, reactors and capacitors;

b) Voltage of all buses;

c) Frequency of all 400 kV and 765 kV bus bars;

d) Frequency of one 220 kV bus;

e) All circuit breakers;

f) All isolators;

g) Tap position for all transformers;

h) master protection signal for all feeders, transformers units and bus bar;

j) loss of voltage signal for bus bar;

k) all the points identified in point (e), (h) and (i) above as gps time stamped;

m) temperature value per substation; and

n) any other point decided during detailed engineering.

ANNEX D

LIST OF ABBREVIATIONS AND SYMBOLS

AES	Advanced encryption standard
AOD	Actual outage duration
AOH	Actual outage hours
BCU	Bay control unit
CB	Circuit breaker
CIP	Critical infrastructure protection
CSD	Controlled switching device
CVT	Capacitive voltage transformer
CT	Current transformer
DES	Data encryption standard
DPC	Digital protection coupler
DR	Disturbance recorder
DXF	Drawing exchange format
E/F	Earth fault
EHV	Extra high voltage
EMC	Electromagnetic compatibility
EMI	Electromagnetic interference
f	Frequency
FAT	Factory acceptance test
GIS	Gas insulated substation
GOOSE	Generic object oriented substation event
GPS	Global positioning system
GR	Group
HDPE	High-density polyethylene
HMI	Human machine interface
HSR	High-availability seamless redundancy
HV	High voltage
I	Current
I/O	Input/output
ICD	Ied configuration description
IEC	International electrotechnical commission
IED	Intelligence electronic device
IEEE	Institute of electrical and electronics engineers
IP	Internet protocol
LAN	Local area network
LBB	Local breaker back-up protection

LN	Logical node
LT	Low tension
MB	Marshaling box
MU	Merging unit
MV	Medium voltage
NAT	Network address translation
NC	Normally closed
NERC	North american electric reliability council
NMS	Network management system
NO	Normally open
O/c	Over-current
O/v	Over-voltage
OLTC	On-load tap changer
OSPF	Open shortest path first
OTI	Oil temperature indicator
P	Active power
PC	Personal computer
PH	Period hours
PMU	Phasor measurement unit
PRP	Parallel redundancy protocol
PSB	Power swing block
PTP	Precision time protocol
Q	Reactive power
RAM	Random access memory
RCC	Remote control centre
REF	Restricted earth fault
RSCC	Remote control and supervision centre
RTCC	Remote tap changer control
RTU	Remote terminal unit
SAS	Substation automation system
SAT	Site acceptance test
SCADA	Supervisory control and data acquisition
SCD	Substation configuration description
SCL	Substation configuration language
SF6	Sulfur hexafluoride
SGC	Switchgear controller
SLD	Single line diagram
SMV	Sampled measured value

SNTP	Simple network time protocol
SOTF	Switch onto fault
TFT	Thin film technology
TS	Technical specification
U	Voltage
U/V	Under volatge
VDU	Visual display unit
VLAN	Virtual LAN
VPN	Virtual private network
VT	Voltage transformer
WTI	Winding temperature indicator

ANNEX E

(*Foreword*)

COMMITTEE COMPOSITION

Power Systems Relays Sectional Committee, ETD 35

Organization	*Representative (s)*
Power Grid Corporation of India, Gurugram	SHRI RAJIL SRIVASTAVA (***Chairperson***)
ABB India Limited, Bengaluru	SHRI M. V. GIRISH SHRI ANOOP AMBAN PARAPURATH (*Alternate*)
Adani Transmission Limited, Ahmedabad	SHRI SANJAY BHATT SHRI UDAY TRIVEDI (*Alternate*)
Ashida Electronics Private Limited, Thane	SHRI SUYASH KULKARNI SHRI SUJAY KULKARNI (*Alternate*)
Bharat Heavy Electrical Limited, New Delhi	SHRIMATI SUNITA RANI ASU SHRI ANIL PAKALAPATI (*Alternate*)
Brihan Mumbai Electric Supply and Transport Undertaking, Mumbai	SHRI G. G.CHANDANKAR
Calcutta Electric Supply Corporation Limited, Kolkata	SHRI ARGHYA GHOSAL SHRI SUCHARIT MONDAL (*Alternate*)
Central Board of Irrigation and Power, New Delhi	SHRI K. P. SINGH SHRI S. K. BATRA (*Alternate*)
Central Electricity Authority	SHRI Y.K. SWARNKAR
Central Power Research Institute, Bengaluru	SHRI KALIAPPAN P. DR MANOHAR SINGH (*Alternate*)
Central Public Works Department, New Delhi	SHRI MUKESH VIJ SHRI V. K. MITTAL (*Alternate*)
Delhi Metro Rail Corporation Limited, Delhi	SHRI ASHISH ARORA SHRI SUBODH PANDEY (*Alternate*)
Delhi Transco Limited, Delhi	SHRI PARITOSH JOSHI SHRI B. L. GUJAR (*Alternate*)
Asun Reyrolle Limited, Hosur	SHRI GEORGE PUNNOOSE SHRI MUTHUKRISHNAN S. (*Alternate*)
Electrical Research and Development Association, Vadodara	SHRI GAUTAM SOM SHRI GAUTAM SOM (*Alternate*)
GE T & D India Limited, Noida	SHRI SUNISH P.
Gujarat Energy Transmission Corporation Limited, Vadodara	SHRI N. M. SHETH
Haryana Vidyut Prasaran Nigam Limited, Gurugram	SHRI RAM NAND MISHRA SHRI PIYUSH SAINI (*Alternate*)
Indian Electrical and Electronics Manufacturers Association, New Delhi	SHRI CHINTAMNI VAZE SHRI UTTAM KUMAR (*Alternate*)
Indian Institute of Science, Bengaluru	PROF D. THUKARAM DR L. UMANAND (*Alternate*)
Indian Institute of Technology Bombay, Mumbai	PROF S. A. SOMAN
Indian Institute of Technology Delhi, New Delhi	PROF M. L. KOTHARI SHRI SUKUMAR MISHRA (*Alternate*)

Organization	*Representative (s)*
Kalki Communication Technologies Private Limited, Bengaluru	SHRI VIJU RAVINDRAN SHRI FAHID KOOLOTH (*Alternate*)
Madhya Pradesh Power Transmission Company Limited, Jabalpur	SHRI B. P. KHORIA SHRI SHIVRAJ SINGH (*Alternate*)
NTPC Limited, New Delhi	DR BHABANI SANKAR SHRI ANKUR TRIPATHI (*Alternate*)
National Hydroelectric Power Corporation, Faridabad	SHRI ANISH GAURAHA SHRI RAJEEV KUMAR (*Alternate*)
Nuclear Power Corporation of India Limited, Mumbai	SHRI SHASHANK SINGH SHRI M. ANANTHACHARI (*Alternate*)
Power Grid Corporation of India, Gurugram	SHRI ABHAY KUMAR
Siemens Limited, Mumbai	SHRI GAGAN KAPOOR SHRI RAHUL SRIVASTAVA (*Alternate*)
Sterlite Power Transmission Limited, New Delhi	SHRI SANDIP MAITY SHRI SUBHASIS JHAMPATI (*Alternate*)
Tata Consulting Engineers Limited, Navi Mumbai	SHRI D. R. SHANTHI
Tata Power Delhi Distribution Limited, New Delhi	SHRI RAJ KUMAR RASTOGI
Tata Power Limited, Mumbai	SHRI G. T. JAWALE SHRI SURENDRA JOSHI (*Alternate*)
The Brihanmumbai Electricity Supply and Transport, Mumbai	SHRI S. N. PAWAR SHRI S. S. ADLINGE (*Alternate*)
Ziv Automation India Private Limited	SHRI R. C. ANAND
BIS Directorate General	SHRI PRITI BHATNAGAR SCIENTIST 'F'/ SENIOR DIRECTOR AND HEAD (ELECTROTECHNICAL) [REPRESENTING DIRECTOR GENERAL (*Ex-officio*)]

Member Secretary
SHRI VISHNU DAYAL JAT
SCIENTIST 'B'/DEPUTY DIRECTOR
(ELECTROTECHNICAL), BIS

This Page has been Intentionally left blank

Bureau of Indian Standards

BIS is a statutory institution established under the *Bureau of Indian Standards Act*, 2016 to promote harmonious development of the activities of standardization, marking and quality certification of goods and attending to connected matters in the country.

Review of Indian Standards

Amendments are issued to standards as the need arises on the basis of comments. Standards are also reviewed periodically; a standard along with amendments is reaffirmed when such review indicates that no changes are needed; if the review indicates that changes are needed, it is taken up for revision. Users of Indian Standards should ascertain that they are in possession of the latest amendments or edition by referring to the website-www.bis.gov.in or www.standardsbis.in.

This Indian Standard has been developed from Doc No.: ETD 35 (12524).

Amendments Issued Since Publication

Amend No.	Date of Issue	Text Affected

BUREAU OF INDIAN STANDARDS

Headquarters:

Manak Bhavan, 9 Bahadur Shah Zafar Marg, New Delhi 110002
Telephones: 2323 0131, 2323 3375, 2323 9402 *Website*: www.bis.gov.in

Regional Offices:		*Telephones*
Central	: 601/A, Konnectus Tower -1, 6th Floor, DMRC Building, Bhavbhuti Marg, New Delhi 110002	2323 7617
Eastern	: 8th Floor, Plot No 7/7 & 7/8, CP Block, Sector V, Salt Lake, Kolkata, West Bengal 700091	2367 0012 2320 9474
Northern	: Plot No. 4-A, Sector 27-B, Madhya Marg, Chandigarh 160019	265 9930
Southern	: C.I.T. Campus, IV Cross Road, Taramani, Chennai 600113	2254 1442 2254 1216
Western	: Plot No. E-9, Road No.-8, MIDC, Andheri (East), Mumbai 400093	2821 8093

Branches : AHMEDABAD. BENGALURU. BHOPAL. BHUBANESHWAR. CHANDIGARH. CHENNAI. COIMBATORE. DEHRADUN. DELHI. FARIDABAD. GHAZIABAD. GUWAHATI. HIMACHAL PRADESH. HUBLI. HYDERABAD. JAIPUR. JAMMU & KASHMIR. JAMSHEDPUR. KOCHI. KOLKATA. LUCKNOW. MADURAI. MUMBAI. NAGPUR. NOIDA. PANIPAT. PATNA. PUNE. RAIPUR. RAJKOT. SURAT. VISAKHAPATNAM.

Published by BIS, New Delhi