

Standard Specification
for
Substation Automation System

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1 GENERAL:

- 1.1. The Substation Automation System (SAS) shall be installed to control and monitor all the sub-station equipment from Remote Control Centers (RCC) & Remote Control and Supervision Centre (RSCC), as well as from local control center.
- 1.2. The SAS shall contain the following main functional parts:
 - Bay Control Unit (BCU) Intelligence Electronic Devices (IEDs) for control and monitoring.
 - Merging Units & Switchgear Controller IEDs (applicable for Process Bus based SAS only)
 - Station Human Machine Interface (HMI) with industrial grade servers
 - Redundant managed switched Ethernet Local Area Network communication infrastructure with hot standby.
 - Redundant Gateway for remote monitoring and control via industrial grade hardware (to RCC) through Secure IEC 60870-5-104 protocol. There will be at least 2 RCCs.
 - 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. It shall be the bidder's responsibility to integrate his offered system with existing RSCC system for exchange of desired data.
 - DR / Engineering PCs, as specified.
 - Remote HMI and workstation along with necessary printers, only if specified in Section Project.
 - Peripheral equipment like printers, display units, keyboards, Mouse 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 and inter IED communication infrastructure. An architecture drawing for SAS is enclosed at [Annexure-II](#).
- 1.5. The communication gateway shall facilitate the information flow with remote control centers. The bay level intelligent electronic devices (IED) 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.
- 1.6. The Sub-station Automation system being offered shall generally conform to provision of IEC 62351, IEEE 1686 and NERC CIP (applicable part such as CIP-003, CIP-005, and CIP-007) for cyber security.
- 1.7. Process bus-based SAS shall be applicable only if specifically envisaged in Section-Project.

2 SYSTEM DESIGN:

2.1 General System Design:

The Substation Automation System (SAS) shall be suitable for operation and monitoring of the complete substation including future extensions as given in Section-

Project.

The systems shall be of the state-of-the art suitable for operation under electrical environment present in Extra high voltage substations, follow the latest engineering practice, ensure long-term compatibility requirements and continuity of equipment supply and the safety of the operating staff.

The offered SAS shall support remote control and monitoring from Remote Control centers via gateways.

The system shall be designed such that personnel without any background knowledge in Microprocessor-based technology are able to operate the system. The operator interface shall be intuitive such that operating personnel shall be able to operate the system easily after having received some basic training.

The system shall incorporate the control, monitoring and protection functions specified, self-monitoring, signaling and testing facilities, measuring as well as memory functions, event recording and evaluation of disturbance records. **It shall also have provisions for inhibiting control on any or all devices for the purpose of maintenance. The devices under maintenance shall be provided with tags which shall include provision for entering text (256 characters).**

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

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

The system shall be remotely accessed for collection of disturbance records and hence shall be provided with a firewall/router to comply at least with the requirements of CIP-005, CIP-007 (Critical infrastructure protection) standard as per NERC (North American Electric Reliability Council).

Bidder shall house the Bay level unit (a bay comprises of one circuit breaker and associated disconnect, earth switches and instrument transformer), bay mimic along with relay and protection panels and PLCC panels (described in other sections of technical specifications) in air-conditioned Switchyard Panel Room suitably located in switchyard (GIS hall relay room in case of GIS s/s) and Station HMI in Control Room building for overall optimization in respect of cabling and control room building.

In case of Process bus based SAS, both bay level unit and station bus level components can also be placed at a centralized location like control room.

2.2 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, i.e. process level, bay level and station level. Process Level will be applicable only in Process Bus based SAS.

At **Process Level** (applicable, only in IEC 61850 Process Bus based SAS) is at the switchyard level where instrument transformers, switchgear, transformers/reactor are located, and employs IEC 61850 part 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 intelligent electronic devices (IED) 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 fiber-optic cables, thereby guaranteeing disturbance free communication. **The fiber optic cables shall be run in G. I. conduit pipes.** Data exchange is to be realized 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.

The communication shall be made in fault tolerant ring, excluding the links between individual bay IEDs to switch wherein the redundant connections are not envisaged, such that failure of one set of fiber shall not affect the normal operation of the SAS. However, failure of fiber shall be alarmed in SAS. **Each fiber optic cable shall have four (4) spare fibers.**

The typical architecture for SAS is enclosed as [Annexure-II](#).

At **Station Level**, the entire station shall be controlled and supervised from the station HMI. It shall also always be possible to control and monitor the bay from the bay level equipment.

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

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

The GPS time synchronizing signal (as specified in the section relay & protection) for the synchronization of the entire system shall be provided. The SAS shall contain the functional parts as described in para 1.2 above.

2.3 Functional Requirements:

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

- Remote control centers
- Station HMI.
- Local Bay controller IED (in the bays)

Operation shall be possible by only one operator at a time with the 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 description in ‘Bay level control function’).

i. Select-Before-Execute:

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.

ii. Command supervision:

Bay/station interlocking and blocking.

Software Interlocking is to be provided to ensure that inadvertent incorrect operation of switchgear causing damage and accidents in case of false operation does not take place.

In addition to software interlocking, hardwired interlocking are to 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 contractor shall describe the scenario while an IED of another bay is switched off or fails.

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

iii. 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 get cancelled, and an alarm shall be generated to indicate the failure of command.

iv. Self-supervision:

Continuous self-supervision function with self-diagnostic feature shall be included. The redundant components such as servers and 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 synchronized from the active server.

3 USER CONFIGURATION:

The monitoring, controlling 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 should be possible).

3.1 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:

- Bay control functions including data collection functionality in bay control/ protection unit.
- Bay protection functions

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

i. Bay control functions:

a. Overview of Function

- Control mode selection.
- Select-before-execute principle.

- Command supervision:
 - Interlocking and blocking
 - Double command
- Synchro check, voltage selection
- Run Time Command cancellation.
- Transformer tap changer control (Raise and lower of tap) (for power transformer bays)
- Transformer Master/follower selection
- Operation counters for circuit breakers and pumps
- Hydraulic pump/ Air compressor runtime supervision
- Operating pressure supervision through digital contacts only
- Breaker position indication per phase
- Alarm annunciation.
- Measurement display
- Local HMI (local guided, emergency mode)
- Interface to the station HMI
- Data storage for at least 200 events
- Auto-reclose mode selection (1-phase/ 3-phase/ 1/3-phase/ Non-Auto etc.)
- Protection transfer switch control (for Transfer Bus scheme arrangement)
- Monitoring of Gas Tight Chambers in GIS
- Monitoring of temperature of Transformer and Reactor
- Monitoring of On-line DGA of Transformer and Reactor
- Monitoring of multi-gas output of Transformer and Reactor
- Any other requirement specified elsewhere in the specification.

b. Control mode selection:

Bay level Operation

As soon as the operator receives the operation access at bay level the operation is normally performed via 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 got 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.

c. 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:

- Settable voltage, phase angle, and frequency difference.
- Energizing for dead line - live bus, live line - dead bus or dead line – dead bus with no

synchro-check function.

- Synchronizing between live line and live bus with synchro-check function

d. Voltage selection:

The voltages relevant for the Synchro check functions are dependent on the station topology, i.e. 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 earthing switch and shall be selected automatically by the bay control and protection IEDs.

e. Transformer tap changer control:

Digital RTCCs shall be integrated with the SAS to provide Tap Changer Control functions.

f. Auto-reclose mode selection:

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

g. 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.

h. 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 inputs are required to be provided in the BCU. In case there is any limitation of number of inputs in the BCU, additional BCUs are required to be provided without any cost implication to Employer. These inputs shall be used for necessary monitoring, control and protection purposes.

ii. Bay protection functions

a. 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 section Relay & Protection.

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.

Event and disturbance recording function- Each IED should contain an event recorder capable of storing at least 200 time-tagged events. The disturbance recorder (DR) function shall be as detailed in Section CRP. The DR(s) shall be integrated with the SAS.

b. 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 (U) and current (I) shall be calculated in the Bay control/protection unit.

3.2 Station Level Functions

i. Status supervision

The position of each switchgear, e.g. 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 position 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 position changes.

The switchgear positions 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 position indications are inconsistent or if the time required for operating mechanism to change position 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 separate one or more IED and all alarm and analogue values shall be monitored and recoded through this IED.

ii. Measurements

The analogue values acquired/calculated in bay control/protection unit shall be displayed locally on the station HMI and in the control centre. The abnormal values must 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 selectable for alarm indications.

iii. 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 on an event list in 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 is enclosed as [Annexure-I](#).

iv. Station HMI

a. Substation HMI Operation:

On the HMI, the object must be selected first. In case of a 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 pressed to close or open the corresponding object.

Control operation from other places (e.g. RCCs) shall not be possible in this operating mode.

b. 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 via mouse clicks.

The HMI shall give the operator access to alarms and events displayed on the screen. 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:

- **Dynamic Single-line diagram showing the switchgear status and measured values**
- **Control dialogues with interlocking or blocking information details.** This control dialogue shall tell the operator whether the device operation is permitted or blocked and show the Interlocking logic with status.
- Measurement dialogues
- Alarm list, station / bay oriented.
- Event list, station / bay-oriented
- System status

c. HMI design principles

Consistent design principles shall be adopted with the HMI concerning labels, colors, dialogues and fonts. Non-valid selections shall be dimmed out. The object status shall be indicated using different status colors for:

- Selected object under command
- Selected on the screen.
- Not updated, obsolete values, not in use or not sampled
- Alarm or faulty state.
- Warning or blocked.
- Update blocked or manually updated.
- Control blocked.
- Normal state
- Energized or energized state (based on substation topology)

d. 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 positions 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 center and device to be controlled is established, the operator shall be prompted to confirm the control action and only then final execute command shall be accepted. After the "execution" of the command the operated switching symbol shall flash until the switch has reached its new position.

The operator shall be able 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 bay and station level.

After command execution the operator shall receive 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.

e. System supervision & display:

The SAS system shall be comprehensively self-monitored such that 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.

f. 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 on the computer for at least one month.** The information shall be obtainable also from a printed event log.

The chronological event list shall contain:

- Position changes of circuit breakers, isolators and earthing devices
- Indication of protective relay operations
- Fault signals from the switchgear
- **Indication when analogue measured values exceed upper and lower limits.** Suitable provision shall be made in the system to define two levels of alarm on either side of the value, or which shall be user defined for each measurands.
- Loss of communication.
- User actions (control/Tag placement/manual update) with USER identity
- System messages (Operator logging info, System supervision and device monitoring, failure of supervisory control etc.)

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

- Date and time.
- Bay
- Device
- Function e.g. trips, protection operations etc.
- Alarm class.

g. 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 (i.e. not flashing) state and the audible alarm should stop.** The alarm should disappear only if the alarm condition has physically 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 for events. In addition to the regular alarms, following alarms shall also be displayed and logged:

- Alarms shall be displayed on the HMI, for each device of SAS when “**Time synchronization**” is lost.
- ‘**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.

h. 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

- Type of blocking/Control inhibit Tag
- Authority
- Local / remote control mode
- RCC / SAS control
- Errors etc.,

shall be displayed.

i. Control dialogues:

The operator shall give commands to the system by means of mouse click located 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:

- Breaker and disconnector
- Transformer tap-changer
- Mode selection (L/R, 1-ph/3-ph/ 1/3-ph/Non-Auto/, Auto/Manual etc.)

v. User-authority levels:

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

- Display only.
- Normal operation (e.g. open/close of switchgear)
- Restricted operation (e.g. by-passed interlocking)
- System administrator

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

- No engineering allowed.
- Engineering/configuration allowed.
- 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 username.

vi. Reports

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

- a. Trend reports:

- Day (mean, peak)
 - Month (mean, peak)
 - Semi-annual (mean, peak)
 - Year (mean, peak)
- b. Historical reports of selected analogue Values:
- Day (at 15 minutes interval)
 - Week
 - Month
 - Year

It shall be possible to select stored values from the database in the process display on-line. Scrolling between e.g. days shall be possible. Unsure values shall be indicated. It shall be possible to select the time period for which the specific data is stored in the memory.

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 value it interrupts (in both conditions i.e. 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 bidder. The bidder has to develop these reports. The reports are limited to the formats for which data is available in the SAS database.
- i. 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 healthiness 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 & 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 do not impact the other applications running in the system.

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

vii. **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 columns 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 selection of threshold values for alarming purposes.

viii. **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 be stored on the hard disc in specified folders.

ix. **Disturbance analysis:**

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

x. **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 allowed after entering a password.

xi. **Automatic sequences:**

The available automatic sequences in the system should be listed and described, (e.g. sequences related to the bus transfer in a Main and Transfer Bus scheme). It must be possible to initiate pre-defined automatic sequences by the operator and define new automatic sequences. The automatic sequencing is required to be developed at SCADA level.

3.3 Gateway:

i. **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) **Two ports for Remote Control Centers on Secure IEC 60870-5-104 protocol.**
- (b) **Two ports for Regional System Coordination Centre (RSCC) on Secure IEC60870-5-104 protocol.**

The communication interface to the SAS shall allow scanning and control of defined points within the substation automation system independently for each control center. The substation automation system shall simultaneously respond to independent scans and commands from employer's control centers (RCCs & 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 center. Also, each control center'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 should 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 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.

ii. Remote Control Centre Communication Interface:

Employer will supply communication channels between the Substation Automation System and the remote-control center. The communication channels provided by Employer will consist either of optical fiber or leased line, the details of which shall be provided during detailed Engineering.

iii. Interface equipment:

The Contractor shall provide interface equipment for communicating between Substation Automation system and Remote-control centers and between Substation Automation system and Regional System Coordination Centre (RSCC). However, the communication channels available for this purpose are specified in Section-Project.

The communication interface with the RCCs is an Ethernet interface. All necessary hardware and software shall also be in the scope of bidder except the communication link along with communication equipment between substation control room and Remote-Control Centre.

iv. Communication Protocol:

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

4 SYSTEM HARDWARE:

4.1 Redundant Station HMI, Remote HMI (Remote HMI only if mentioned in section project) and Disturbance Recorder Workstation:

The contractor shall provide redundant station HMI in hot standby mode. The servers used on these workstations shall be of **industrial grade**.

It shall be capable of performing all functions for the 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% capacity of processing and memory are used.** Supplier shall demonstrate these features during FAT.

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

1. Storage of all analogue data (at 15 Minutes interval) and digital data including alarm, event for two years and trend data for thirty (30) days,
2. Storage of all necessary software,
3. 500GB space for Employer's use.

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

requirement.

i. HMI (Human Machine Interface)

The 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 selectable in the form of lists. Operation shall be by a user-friendly function keyboard and a cursor positioning device. The user interface shall be based on WINDOWS concepts with graphics & facility for panning, scrolling, zooming, decluttering etc.

ii. 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 32" diagonally in size** and capable of colour graphic displays.

The display shall accommodate resolution of **1280 X 1024 pixels**.

iii. Printer

It shall be robust & 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 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. All printers shall be continuously online.

iv. Mass Storage Unit

The mass storage unit shall be built-in to the Station HMI. All operational measured values, and indications shall be stored in a mass-storage unit in form of DVD RW. The unit should support at least Read (48X), Write(24X), and Re-Write (10X) operations, with multi-Session capability. It should support ISO 9660, Rockridge and Joliet File systems. It should support formatting and use under the operating system provided for Station HMI. The monthly backup of data shall be taken on disc. The facility of backing up of data shall be inherent in the software.

v. Switched Ethernet Communication Infrastructure:

The bidder 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 and 400kV yard and for two bays of 220kV yard to communication infrastructure. Each switch shall have at least two spare ports for connecting bay level IEDs and one spare port for connecting station buses.**

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

In addition to above, the bidder shall also provide 2 Nos. managed Ethernet switches with at least 16 copper RJ45 ports on each switch to form managed "Redundant System LAN". These switches shall be different from IEC 61850 LAN and specifically used for the purpose of connecting various devices of different sub-system (SCADA, Gateway, VMS, VOIP etc.)

for integration with RCC/RSCC. These switches shall be suitable for substation environment and shall comply with the requirements of IEC 61850-3 standard for EMI/EMC.

These LAN switches shall have the following compliance and functional features:

- a. Compliance as per ERC-CIP-3, NERC-CIP-5, NERC-CIP-7 standard for cyber security.
- b. Support SNMPv3 (Full SNMP support including Traps)
- c. Web based GUI or CLI based with HTTPS/HTTP and SSH/Telnet support.
- d. Support for IPv4 and IPv6 switching simultaneously.
- e. Layer 3 static routing functionality.
- f. Syslog facility for local as well as remote server.
- g. Support for remote management.
- h. LED indication for port status/supply etc.
- i. Shall support VLAN IEEE802.1Q.
- j. IGMP snooping.
- k. Spanning tree protocol IEEE802.1d or RSTP IEEE 802.1w
- l. Shall support STP.
- m. Port based Network Access control (IEEE 802.1x).
- n. Quality of service (IEEE 802.1p).
- o. Shall support unicast as well as multicast IP traffic.
- p. STP time synchronization.
- q. Shall support Mac Binding.
- r. Fanless design.

vi. Firewall and Router

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

The substation Routers shall have the following features:

- Routing protocols such as OSPF and support for IPv4 and IPv6
- 4 Ethernet interfaces of 10/100 Mbps
- 2 E1 interfaces
- Hot standby operation with a similar router
- Support IEEE 802.3u, 802.1p, 802.1Q, 802.1d, 802.1w,
- Traffic prioritization for routed IP flows/ports the substation firewall and router can be a single device.

The substation Firewall shall have the following features:

- IP firewall features such as Address/port inspection and filtering
- Shall be stateful firewall
- Shall support upto 4 Ethernet switches 10/100 Mbps
- Shall support simultaneous operation for both IPv4 and IPv6
- Shall have IP sec/VPN with 3DES/AES encryption
- Shall have NAT
- Shall have syslog capability
- Shall be NERC compliant
- Shall have hot- standby operation with similar router

The detailed specification of Next generation Router-cum-Firewall shall be as per RfP.

The 2 Nos. Managed Ethernet switches as detailed above, Next generation firewall and router can be clubbed or separate hardware.

4.2 Bay level unit or Bay control unit (BCU):

i. General:

- Bay Control Unit (BCU) shall be provided for each Bays (a bay comprises of one circuit breaker and associated disconnecter, earth switches and instrument transformer, Number of bays shall be as per Section-Project for control and monitoring of the bay equipment. Separate BCU (as per section-project) shall be provided for the monitoring of substation auxiliaries.
- The BCUs shall have adequate capacity for the estimated hardwired Inputs & Outputs plus a **minimum of two Inputs and a minimum of two outputs as 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 bay from BCU whenever required. The Local HMI facilities shall be accomplished 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 issuance 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 should be applied based on hardwired analog/digital inputs or Process Bus signals. In the event of closing control for circuit breakers requiring checking of synchronization conditions, software synchro-check scheme should be applied as well. Auto-reclose functions mentioned elsewhere in the specification, if required, can also be applied.

ii. 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 capable of restarting automatically. Time synchronization of BCUs with UTC time shall be done over the IEC 61850 field LAN for Substation with SAS. For conventional substation, Time synchronization of BCU shall be done by other suitable Time synch input like IRIG-B, RS232 etc.
- They 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. They 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 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, this shall receive the operation commands from station HMI and control center.

- **One no. Bay Control unit shall be provided for supervision and control of each 765, 400, 220, 132 kV bay (a bay comprises of one circuit breaker and associated disconnecter, earth switches and instrument transformer).** 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 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.
- The bay control unit to be provided for the bays shall preferably be installed in the CB relay panel/feeder protection panel for respective bay. Further in case of one and half breaker schemes, the BCU for Tie CB shall be provided in Tie CB relay panel. **The tie CB relay panel shall also house the Ethernet switch(es) to be provided for the diameter. The bay control unit for future bays (if required as per section project) 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.

iii. 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 (i.e. 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.
- The BCU/IED shall be able to integrate **at least 10 analog input channels as a minimum** and digital input / output channel to meet the control & 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, i.e. 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 1 ms 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 0-10/4-20mA and -10 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 & execute sequence (or other means of providing high message security).

- iv. The BCU supplied for substation automation system shall further meet the requirements mentioned elsewhere in the specification.

4.3 Extendibility in future:

Offered substation automation system shall be suitable for extension in future for additional bays. During 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 employer. During such event, normal operation of the existing substation shall be unaffected, and system shall not require a complete shutdown. **The contractor shall provide all necessary software tools along with details to perform addition of bays in future and complete integration with SAS by the user.** These software tools shall be able to configure IED, add additional analogue variables, 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:

- All the licenses for various components such as SCADA, Servers, configuration tools for various IEDs, Gateways etc. shall be for complete system i.e. system as per single line diagram including both present and future scope. The contractor shall submit the list of equipment and Inputs/Outputs covered under the licenses provided.
- 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.

5 SOFTWARE STRUCTURE:

The software package shall be structured according to the SAS architecture and strictly divided into various levels. Necessary firewalls 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.

5.1 Station level software:

i. 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.

5.2 Bay level software:

i. System software

The system software shall be structured into 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 synchronizing with the remaining system without any manual interface. This shall be demonstrated by the contractor during integrated system test.

ii. 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 form part of a library.

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

5.3 Network Management System:

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

- a. Configuration Management
- b. Fault Management
- c. Performance Monitoring

This system shall be used for the management of communication devices and other IEDs in the system. This NMS can be loaded in DR workstation 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 occurs.
- d. Provide facility to add and delete addresses and links.

5.4 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.

i. Secure Build Strategy

Packages unnecessary for system operation are 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 have to be disabled.

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

- Games
- Messaging services
- Servers or clients for unused Internet services
- Software compilers (except where required, i.e. development platform)
- Unused networking and communication protocols
- Unused operating system features
- free utilities delivered with Operating System

ii. 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 are disabled from all interactive, network, or other access to prevent unauthorized access. Required accounts and their functions have to be documented.

iii. Insecure Protocol

Insecure protocols such as telnet, FTP, RSH, and RCP etc. have to be disabled from operation.

iv. Malicious Software Prevention

Implementation of anti-virus and other malicious software prevention tools 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 harm to the product.

Provide procedures on how to update the signature database of the anti-malware software, if provided.

v. System Whitelisting

System whitelisting is to 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.) are prevented from executing.

vi. 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 required for operation are documented and supplied to the customer as part of the deliverable system documentation.

vii. 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 firewall fails. 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.

viii. 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 as per specification.

- 5.5 The contractor shall provide each software in two copies in CD to load into the system in case of any problem related with Hardware/Communication etc.

6 GENERAL GUIDELINES FOR IEC 61850 SAS ENGINEERING:

- 6.1 Data exchange is to be realized 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.

- 6.2 **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 which it receives without the quality attribute.**
- 6.3 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. Once duplicate GOOSE messages or intrusion is detected, the subscribing device shall discard the GOOSE messages from that publishing device and shall generate an alarm.
- 6.4 If the association between the publisher and subscriber is lost (Refer Sec. 6.2 of IEC 61850 part 7-3), the ‘validity’ field of the quality will be set to “questionable”, and the “detailQual” will be set to ‘oldData’. The rest of quality fields will not be changed.
- 6.5 **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.
- 6.6 A guideline over usage of logical nodes for Report Control/ GOOSE control engineering shall be issued during the detailed engineering.
- 6.7 **In the Control and Protection schemes, wherever GOOSE messages are used, the schematic documents submitted by the vendor should indicate the communication between LNs used in indicating the source and destination LNs.**

7 ADDITIONAL REQUIREMENTS FOR IEC 61850 BASED PROCESS BUS PROJECTS (APPLICABLE ONLY IF PROCESS BUS SAS IS SPECIFIED IN SECTION-PROJECT):

7.1 Switchgear Controllers (SGC) IED:

- 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.
- 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, 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.
- 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. The engineering of the device shall comply with IEC 61850 Part 6 (Substation Configuration Language). Further, to accommodate supervision inputs and other 4-20mA inputs, Logical Nodes, as defined in the standard (the latest edition of IEC 61850) shall be used.
- The devices shall use Parallel Redundancy Protocol (PRP) and be High- availability Seamless Redundancy (HSR) capable. 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.
- The user shall be able to configure/access the device from the Engineering PC in the Control Room.

- The number of binary inputs and binary outputs along with 4-20mA 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.
- Each bay shall have at least one SGC.
- SGCs should be powered by redundant Station DC power supplies and if the same is not available, then external changeover circuit shall be used.

7.2 Merging Units (MU) for Conventional CT and VT

- Merging Units (MU) shall digitize the conventional CT and VT values as per IEC 61850 Sampled Measured Values (SMV).
- 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, electromagnetic interference (EMI/EMC) conditions, radio interference etc. MUs 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.
- 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. The engineering of the device shall comply with IEC 61850 Part 6 (Substation Configuration Language).
- 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 purpose.
- The user shall be able to configure/access the device from a separate Engineering PC in the Control Room.
- Each bay shall have 2 nos. MUs, each having CT and CVT inputs from different cores. For Bus CVTs, separate MUs shall be provided.
- MUs should be powered from Station DC power supplies, one from source-1 & other from source-2.

7.3 Specific Requirement for Control & Protection IEDs to be used in Process Bus SAS:

- 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 number of ports natively in the IED are not available, then Redundancy Boxes (Redbox) shall be used. However, at least 2 ports shall compulsorily be available natively 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).
- The IEDs, wherever required, shall have the capability to internally summate the Sampled Values (SV) streams from two or more instrument transformers.

7.4 For Transformers and Reactors, sufficient (redundant)SGCs/MUs shall be provided in the Transformer/Reactor MB (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.

- 7.5 Following alarms shall be generated by devices subscribing to SMV streams in the following two cases:
- Firstly, when a subscribing IED stops receiving SMV streams from the Merging Unit(s), alarms shall be generated.
- Secondly, 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.
- 7.6 In addition to the requirements specified at Section 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.
- 7.7 The architecture of Process Bus based SAS shall be such that the failure of any one Ethernet switch or any one fiber section of the SAS LAN (either in Process Bus LAN or in Station Bus LAN) shall not result into any communication interruption.
- 7.8 All the control and protection schemes/functions shall be designed and implemented with GOOSE messages and Sampled Values, unless specifically desired by Employer to be implemented using hardwiring. For energy metering, hardwiring between CT & CVT and meters shall be done. For signal exchange between PLCC 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.

8 TESTS:

The substation automation system offered by the bidder 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 and specified ambient conditions:

8.1 Type Tests:

1. Control IEDs /BCU and Communication Equipment:

The above equipment shall conform to following type tests as per IEC 61850-3 (latest Revision)

- a. Power Input:
 - Auxiliary Voltage
 - Current Circuits
 - Voltage Circuits
 - Indications
- b. Accuracy Tests:
 - Operational Measured Values
 - Currents
 - Voltages
 - Time resolution
- c. Insulation Tests:
 - Dielectric Tests
 - Impulse Voltage withstand Test
- d. Influencing Quantities

- Limits of operation
 - Permissible ripples
 - Interruption of input voltage
 - e. Electromagnetic Compatibility Test:
 - 1 MHZ burst disturbance test
 - Electrostatic Discharge Test
 - Radiated Electromagnetic Field Disturbance Test
 - Electrical Fast transient Disturbance Test
 - Conducted Disturbances Tests induced by Radio Frequency Field
 - Magnetic Field Test
 - Emission (Radio interference level) Test.
 - Conducted Interference Test
 - f. Functional Tests:
 - Indication
 - Commands
 - Measured value Acquisition.
 - Display Indications
 - g. Environmental tests:
 - Cold Temperature
 - Dry Heat
 - Wet heat
 - Humidity (Damp heat Cycle)
 - Vibration
 - Bump
 - Shock
2. All the IEDs, 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.

8.2 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 Employer. The Standard SAS FAT format & procedure is provided at Annexure-III for reference guidelines. For the individual bay level IED's 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 Contractor has interpreted the specified requirements correctly and that the FAT includes checking to the degree required by the user. The general philosophy shall be to deliver a system to site only after it has been thoroughly tested and its specified performance has been verified, as far as site conditions can be simulated in a test lab. **During FAT, the entire Substation 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 site. No major configuration setting of system is envisaged at site.

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

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 as part of site acceptance test (SAT).

In case of an 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 as part of SAT.

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 the 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 vendor 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.**

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 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.

8.3 Site Acceptance Tests:

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

9 SYSTEM OPERATION:

9.1 Substation Operation

1. Normal Operation

Operation of the system by the operator from the 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 colored screen shall be divided into 3 fields:

- Message field with display of present time and date
- Display field for single line diagrams
- 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 (i.e. operator prompting). For control actions, the switchgear (i.e. 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 color. The operator prompting shall distinguish between:

- Prompting of indications e.g. fault indications in the switchgear, and
- prompting of operational sequences e.g. 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 accessed 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.

The offer shall include a comprehensive description of the system. The above operation shall also be possible via WINDOWS based system by mouse.

10 POWER SUPPLY:

Power for the substation automation system shall be derived from station DC power supplies.

The inverter of adequate capacity (Main + standby) shall be provided for station HMI disturbance recorder evaluation unit and its peripheral devices e.g. 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 & hot standby SAS system. A separate Inverter shall also be supplied for Remote HMI & Workstation only if applicable.

11 DOCUMENTATION:

The following documents shall be submitted for employer'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 supplier
- (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 to be provide in "dxf" format.

- List of Drawings
- Substation automation system architecture
- Block Diagram
- Guaranteed Technical Parameters, Functional Design Specification and Guaranteed availability and reliability
- Calculation for power supply dimensioning
- I/O Signal lists
- Schematic diagrams
- List of Apparatus
- List of Labels
- Logic Diagram (Hardware & Software)
- Switchyard Panel Room layout drawing
- Control Room Layout
- Test Specification for Factory Acceptance Test (FAT)
- Test Specification for Site Acceptance Test (SAT)
- The SCD files of the station's project shall be submitted by the vendor during the FAT and

- after successful commissioning of SAS.
- A GOOSE matrix sheet with publisher and subscriber IEDs.
- Product Manuals (Installation, Configuration, maintenance, Troubleshooting, detailed diagnostics etc.)
- Assembly Drawing
- Operator's Manual
- Complete documentation of implemented protocols between various elements
- Listing of software and loadable in CD ROM
- 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.

12 TRAINING, SUPPORT SERVICES:

12.1 Training

The contractor shall arrange on its own cost all hardware training platform required for successful training and understanding in India. The Contractor shall provide all necessary training material. Each trainee shall receive individual copies of all technical manuals and all other documents used for training. These materials shall be sent to Employer at least two weeks before the scheduled commencement of the training course.

For all training courses, the travel (e.g., airfare) and per-diem expenses will be borne by the participants. The schedule, location, and detailed contents of each course will be finalized during Employer and Contractor discussions.

The contractor shall provide training (minimum 2 weeks) for Employer personnel (8 to 10) covering the following courses comprehensively.

12.2 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 Employer 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
- (b) Equipment Maintenance
- (c) System Expansion
- (d) System Maintenance
- (e) Subsystem Maintenance
- (f) Operational Training

12.3 Computer System Software Course

- (a) System Programming
- (b) Operating System
- (c) System Initialization and Failover
- (d) Diagnostics
- (e) Software Documentation
- (f) Hands-on Training

12.4 Application Software Course:

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

- (a) Overview
- (b) Application Functions
- (c) Software Development
- (d) Software Documentation
- (e) Hands-on Training

13 MAINTENANCE:

Maintenance Responsibility during the Guaranteed Availability Period.

During Guaranteed Availability Period, the Contractor 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, contractor shall arrange visit of SAS manufacturer's representative to site as per requirement to review the performance of system and in case any defect/shortcoming etc. is observed during the period, the same shall be set right by the contractor within 15 days.

14 RELIABILITY AND AVAILABILITY:

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

- Mechanical and electrical design
- Security against electrical interference (EMI)
- High quality components and boards
- Modular, well-tested hardware
- Thoroughly developed and tested modular software
- Easy-to-understand programming language for application programming
- Detailed graphical documentation and application software
- Built-in supervision and diagnostic functions
- Security
 - Experience of security requirements
 - Process know-how
 - Select before execute at operation
 - Process status representation as double indications
- Distributed solution
- Independent units connected to the local area network
- Back-up functions
- Panel design appropriate to the harsh electrical environment and ambient conditions
- Panel grounding immune against transient ground potential rise

Outage terms

1) Outage

The state in which substation automation system or a unit of SAS is unavailable for Normal Operation as defined in the clause 9.1.1 due to an event directly related to the SAS or unit of SAS. In the event, the owner has taken any equipment/system other than Sub-station Automation System for schedule/forced maintenance, the consequent outage to SAS shall not be considered as outage for the purpose of availability.

2) Actual outage duration (AOD)

The time elapsed in hours between the start and the end of an outage. The time shall be counted to the nearest 1/4th of an hour. Time less than 1/4th of an hour shall be counted as having duration of 1/4th of an hour.

3) Period Hours (PH)

The number of hours in the reporting period. In a full year the period hours are 8760h (8784h for a leap year).

4) Actual Outage hours (AOH)

The sum of actual outage duration within the reporting period $AOH = \sum AOD$

5) Availability:

Each SAS shall have a total availability of 99.98 % i.e.

$$\frac{\text{Total time duration} - \text{Actual outage duration}}{\text{Total time duration}}$$

14.2 Guarantees Required

The availability for the complete SAS shall be guaranteed by the Contractor. The contractor shall demonstrate their availability guaranteed by conducting the availability test on the total sub-station automation system as a whole after commissioning of total Sub-station Automation system. 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%. After the lapse of 1000 Hours 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 contractor shall rectify the problem and after rectification, the 1000 Hours period starts after such rectification. If the test object has not been met the overall availability, the test shall continue until the specified availability is achieved.

The contractor has to establish the availability in a maximum period of three months from the date of commencement of the availability test.

After the satisfactory conclusion of test, both contractor and employer shall mutually agree to the test results and if these results satisfy the availability criterion, the test is considered to be completed successfully. After that the system shall be taken over by the employer and then the guarantee period shall start.

15 SPARES:

15.1 Consumables:

All consumables such as paper, cartridges shall be supplied by the contractor till the SAS is taken over by the owner.

15.2 Availability Spares:

In addition to mandatory spares as listed in Section-Project for SAS/BOQ, the bidder is required to list the spares, which may be required for ensuring the guaranteed availability during the guaranteed availability period.

During the guaranteed availability period, the spare parts supplied by the Contractor shall be made available to the Contractor for usage subject to replenishment at the earliest. Thus, at the end of the availability period, the inventory of mandatory spares with the Employer shall be fully replenished by the Contractor. However, any additional spares required to meet the availability of the system (which are not a part of the above spares supplied by the Contractor) would have to be supplied immediately by the Contractor free of cost to the Employer.

The price of the above availability spare, as assessed by the SAS vendor, shall be deemed to be included in the complete SAS price.

15.3 Special Tools for IEC 61850 based SAS:

The contractor 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 .cid/.scd file(s) and simulate them.

For IEC 61850 based Process Bus Projects, the bidder also shall supply a SV (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.

The price of the above shall be deemed to be included in the complete SAS.

16 LIST OF EQUIPMENTS:

Quantity of following equipment shall be decided by bidder in order to achieve guaranteed reliability and availability as declared by bidder.

- i) Station HMI workstation
- ii) Redundant Station HMI (in Hot standby mode) workstation
- iii) Disturbance Recorder Workstation (Maintenance HMI)
- iv) Bay level units along with bay mimic for number of bays as detailed in Section Project.
- v) Bay Level Unit for Auxiliary system (as per requirement)
- vi) Colour Laser Printer – 1 No. (For Reports & Disturbance records)
- vii) All interface equipment for Gateway to RCC and RSCC
- viii) Communication infrastructure between Bay level units, Station HMI, Printers, Gateways, redundant LAN etc. as required.
- ix) Managed Station Ethernet Switch – 2 Nos.
- x) Next Generation Router-cum-Firewall – 2 Nos.
- xi) Modems as per requirement.
- xii) Remote disturbance recorder workstation and remote HMI and along with one colour laser A4 printer (Remote HMI, only if specified in Section Project).
- xiii) Merging Units (MUs) [applicable for Process Bus SAS], as per requirement.
- xiv) Switchgear Controllers (SGCs) [applicable for Process Bus SAS], as per requirement.
- xv) Engineering PC for Merging Units (applicable in case of Process Bus Projects)
- xvi) Any other equipment as necessary.

ANNEXURE-I: List of Analogue and Digital Inputs

Basic Monitoring requirements are:

- (a) Switchgear status indication
- (b) Measurements (U, I, P, Q, f)
- (c) Event
- (d) Alarm
- (e) Acquisition of Alarm and Fault record from Protection Relays
- (f) Disturbance Records
- (g) Acquisition of all counters in PLCC panels through potential free contacts from PLCC or independently by counting the receive/send commands.
- (h) Oil & Winding temperature of Transformer & Reactor individual units.
- (i) Tap-position of Power Transformer
- (j) Temperature measured with Optical Temperature sensor (being provided by Transformer/Reactor manufacturer)
- (k) Dissolved Hydrogen / multi-gas & Moisture Content monitor of Transformer/Reactor
- (l) Status and display of LT transformer & its associated switchgear for Station Auxiliary Supply
- (m) Status and display of 415V LT system, 220V & 48V DC system
- (n) Monitoring the state of Batteries by displaying DC voltage, Charging current and Load current etc.
- (o) Status of display of Fire protection system and Air conditioning system.
- (p) Ambient Temperature

List of Inputs:

The list of input for typical bays is as below:

A	Analogue inputs	
i.	For Each Line	
	Current	R Phase
		Y Phase
		B Phase
	Voltage	R-Y phase
		Y-B phase
		B-R phase
ii	For Each Transformer/Reactor	
	Current	R Phase
		Y Phase
		B Phase
		WTI (Winding wise)
		OTI
		Multi-gas DGA /Moisture parameters
		Tap position (for Transformer only)
iii	For TBC and Bus coupler	
	Current	R Phase
		Y Phase

		B Phase
iv	Common	
a.	Voltage for Bus-I, Bus-II and Transfer bus (As applicable)	
	Voltage	R-Y phase
		Y-B phase
		B-R phase
b.	Frequency for Bus-I and Bus-II	
c.	Ambient Temperature (Switchyard)	
d.	Switchyard Panel Room Temperature	
e.	LT system	
	1. Voltage R-Y, Y-B, B-R of Main Switch Board Section-I	
	2. Voltage R-Y, Y-B, B-R of Main Switch Board Section-II	
	3. Voltage R-Y, Y-B, B-R of Diesel Generator Set	
	4. Current from LT Transformer-I	
	5. Current from LT Transformer-II	
	6. Current from Diesel Generator	
	7. Voltage of 220V DCDB-I	
	8. Voltage of 220V DCDB-II	
	9. Current from 220V Battery Set-I	
	10. Current from 220V Battery Set-II	
	11. Current from 220V Battery Charger-I	
	12. Current from 220V Battery Charger-II	
	13. Voltage of 48V DCDB-I	
	14. Voltage of 48V DCDB-II	
	15. Current from 48V Battery Set-I	
	16. Current from 48V Battery Set-II	
	17. Current from 48V Battery Charger-I	
	18. Current from 48V Battery Charger-II	
B	Digital inputs	
	The list of input for various bays/System is as follows:	
i.	Line Bays	
	1. Status of each pole of CB.	
	2. Status of Isolator, Earth switch	
	3. CB trouble alarms	
	4. CB operation/closing lockout	
	5. Pole discrepancy operated	
	6. Trip coil faulty	
	7. LBB operated	
	8. Bus bar protection trip relay operated	
	9. Main Breaker Auto-Recloser operated	
	10. Tie/Transfer Breaker Auto-Recloser operated	
	11. A/R lockout	
	12. Tie/Transfer Breaker Auto-Recloser lockout	
	13. Direct trip-I/II sent	
	14. Direct trip-I/II received	
	15. Main I/II blocking	
	16. Main I/II-Inter trip send	
	17. Main I/II-Inter trip received	
	18. O/V Stage – I operated	
	19. O/V Stage – II operated	

	20. Fault Locator Faulty (As applicable)
	21. Main-I/II CVT Fuse Fail
	22. Main -I Protection Trip
	23. Main -II Protection Trip
	24. Main -I PSB Alarm
	25. Main -I SOTF Trip
	26. Main -I R-Ph Trip
	27. Main -I Y-Ph Trip
	28. Main -I B-Ph Trip
	29. Main -I Start
	30. Main -I Carrier aided trip
	31. Main -I/II Fault in Reverse direction
	32. Main -I/II Zone-2 Trip
	33. Main -I/II Zone-3 Trip
	34. Main -I/II Weak end infeed operated (As applicable)
	35. Main -II PSB Alarm
	36. Main -II SOTF Trip
	37. Main -II R-Ph Trip
	38. Main -II Y-Ph Trip
	39. Main -II B-Ph Trip
	40. Main -II Start
	41. Main -II Carrier aided trip
	42. Main -I/II Back-up O/C operated
	43. Main -I/II Back-up E/F operated
	44. 220V DC-I/II source fail
	45. Speech Channel Fail (As applicable)
	46. PLCC Protection Channel-I Fail
	47. PLCC Protection Channel-II Fail
ii	Transformer bays (HV Side)
	1. Status of each pole of CB,
	2. Status of Isolator, Earth switch
	3. CB trouble
	4. CB operation/closing lockout
	5. Pole discrepancy operated
	6. Trip coil faulty
	7. LBB operated
	8. Bus bar protection trip relay operated
	9. Differential Protection operated (Phase Wise)
	10. REF Protection operated (Phase Wise in case of 1-Phase units)
	11. Over-Flux Alarm (HV)
	12. Over-Flux Trip (HV)
	13. Over-Flux Alarm (IV)
	14. Over-Flux Trip (IV)
	15. Back-up O/C (HV) Operated
	16. Back-up E/F (HV) Operated
	17. Back-up O/C (IV) Operated
	18. Back-up E/F (IV) Operated
	19. Back-up Impedance Operated (As applicable)
	20. GR-A Protection Operated
	21. GR-B Protection Operated

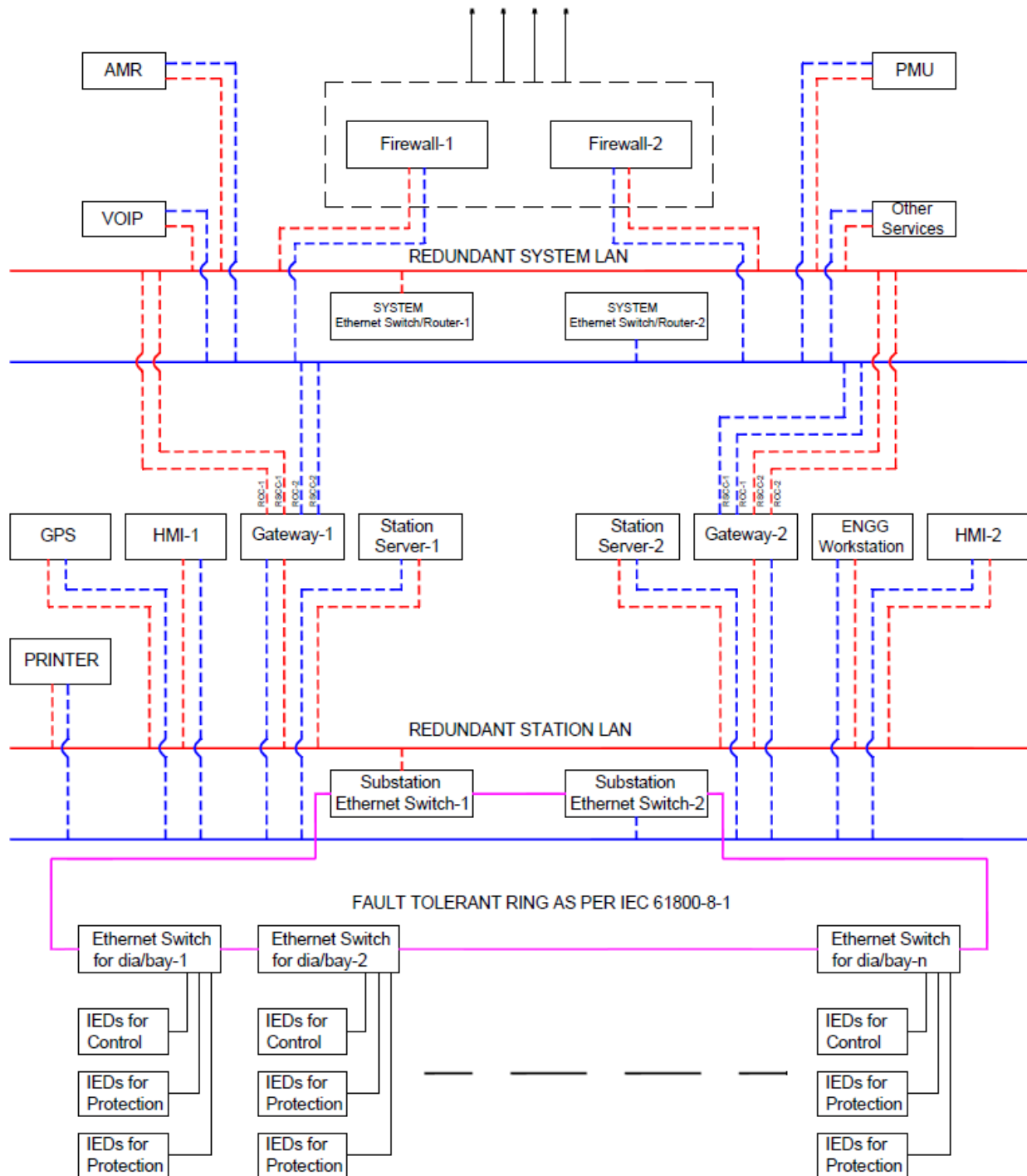
	22. HV Bus-1/2 CVT Fuse Fail
	23. IV Bus-1/2 CVT Fuse Fail
	24. OTI Alarm/Trip
	25. HV/IV/LV WTI Alarm/Trip
	26. PRD Operated (each PRD)
	27. Over-Load Alarm
	28. Buchholz Alarm (each Buchholz)
	29. Buchholz Trip (each Buchholz)
	30. OLTC BUCHOLZ Alarm
	31. OLTC BUCHOLZ Trip
	32. MOG Low Oil Level Alarm
	33. TAP Mismatch
	34. 220V DC-I/II source fail
	35. Healthiness of each Protection Relay through watchdog contact
iii	Transformer bays (IV Side)
	1. Status of each pole of CB, Isolator, Earth switch
	2. CB trouble
	3. CB operation/closing lockout
	4. Pole discrepancy operated
	5. Trip coil faulty
	6. LBB operated
	7. Bus bar protection trip relay operated
	8. 220V DC-I/II source fail
	9. GR-A Protection Operated
	10. GR-B Protection Operated
iv	Line/Bus Reactor bays (as applicable):
	1. Status of each pole of CB, Isolator, Earth switch
	2. CB trouble
	3. CB operation/closing lockout
	4. Pole discrepancy operated
	5. Trip coil faulty
	6. LBB operated
	7. Bus bar protection trip relay operated
	8. Differential Protection operated (Phase Wise)
	9. REF Protection operated (Phase Wise in case of 1-Phase units)
	10. Back-up impedance Protection operated
	11. Line/ Bus-1/2 CVT Fuse Fail
	12. OTI Alarm/Trip
	13. WTI Alarm/Trip
	14. PRD Operated (each PRD)
	15. Buchholz Alarm (each Buchholz)
	16. Buchholz Trip (each Buchholz)
	17. MOG Low Oil Level Alarm
	18. 220V DC-I/II source fail
	19. GR-A Protection Operated
	20. GR-B Protection Operated
v	Bus bar Protection
	1. Bus Bar Main-I Zone-I/II/Transfer trip
	2. Bus Bar Main-II Zone-I/II/Transfer trip
	3. Bus bar Zone-I CT open

	4. Bus bar Zone-II CT open
	5. Bus Transfer CT open
	6. Bus transfer bus bar protection operated
	7. Bus protection relay fail
vi	Auxiliary system
	1. MSB Incomer-I On/Off
	2. MSB Incomer-II On/Off
	3. MSB Bus Coupler On/Off
	4. DG set Breaker On/Off
	5. 415V Bus-I/II U/V
	6. Time sync. Signal absent
	7. PLCC exchange fail
	8. LT Transformer-I Buchholz Alarm & trip
	9. LT Transformer-II Buchholz Alarm & trip
	10. LT Transformer-I WTI Alarm & trip
	11. LT Transformer-II WTI Alarm & trip
	12. LT Transformer-I OTI Alarm & trip
	13. LT Transformer-II OTI Alarm & trip
	14. Alarm/trip signals as listed in Section: DG set
	15. Alarm/trip signals as listed in Section: Battery and Battery charger
	16. 220V DC-I Earth Fault
	17. 220V DC-II Earth Fault
	18. Alarm/Trip signals as listed in Section: Fire protection system
vii	Switchyard Panel Room:
	1. AC Compressor 1 ON/OFF
	2. AC Compressor 2 ON/OFF
	3. Fire Detection 1 ON/OFF
	4. Fire Detection 2 On/OFF
	5. Switchyard Panel Room Temperature High Alarm

The exact number and description of digital inputs shall be as per detailed engineering requirement. **Apart from the above-mentioned digital inputs, minimum of 200 inputs shall be kept for employer's/owner's use in future for new substations. For extension substations, minimum 04 nos. digital inputs per bay shall be kept for future use.**

ANNEXURE-II: Typical Architecture Drawing

Typical Architectural Drawing of Substation Automation System (Without Process Bus)



Note:

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 clause no. 1.1 and 3.3 of this specification.
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 workstation.

5. RCC means CCR/Backup CCR. Similarly, RSCC means RLDC/Backup RLDC for ISTS system and SLDC/Backup SLDC for state owned substations/bays.
6. The above layout is typical. However, if any contractor offers slightly modified architecture based on their standard practice without compromising the working, the same shall be subject to approval during detailed engineering.

List of IO Points to be transmitted to RSCC.

1. MW and MVAR for all lines, Transformers, Reactors and Capacitors
2. Voltage of all buses
3. Frequency of all 400kV and 765kV Buses
4. Frequency of one 220Kv Bus
5. All Breakers/Isolator status
6. Tap Position for all transformers.
7. Master protection signal for all Line feeders, Transformers, Reactors and Bus Bar
8. Loss of Voltage signal for Bus bar
9. All the points identified in point (1) and (7) above as GPS Time stamped.
10. Ambient Temperature.
11. Any other point decided during detailed engineering.