

ATTACHEMENT 06

ISECTION 5
SUBSTATION AUTOMATION SYSTEM
Protection, Metering and Control

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SECTION 5

SUBSTATION AUTOMATION SYSTEM

Protection, Metering and Control

5.1 General

The protection and control facilities shall be suitable for the power system arrangement as shown on the Single Line Drawing and Trip Logic provided with the bid document.

5.1.1 For each substation, the Contractor has to foresee one (or more) separate cubicle(s) for:

- Control system – SCADA Server (Control, SCADA, SAS, etc.)
- Operator's Working Station
- Gateway server
- DFDR
- AVR
- Protection system
- Metering
- 33 kV Control cubicle(s)

During the Design stage, the Contractor has to propose the final solution, which will be subject of the Employer's final approval.

5.1.1.1 The Main 1 & Main 2 relays of the same protected object shall be from different manufacturers or different model from the same manufacturer.

5.1.1.2 During the Design stage, the Contractor can propose different arrangement like:

- Main 1 Protection and Main 2 Protection in the same cubicle and separate Control cubicle or
- Both Protection and Control in the same cubicle for lower voltage class like 132kV & lowers

5.1.1.3 The final solution will be subject of the Employer's final approval. However, the bidder/manufacturers of relay shall provide at least 5 years of warranty for its product, i.e., for complete Protection system.

5.2 Protection Relay - General

5.2.1 For standardization of operating performance, facilities and spare requirements, the protection relays and control systems, together with complete panels to be supplied under this project shall be manufactured by Hitachi (Switzerland/Sweden), Alstom/GE (France/UK/USA), Siemens (Germany), SEL (USA/UK/Canada) or equivalent. Since some of the above mentioned make, viz., Hitachi (Switzerland/Sweden), Alstom/GE (France/USA/UK), SEL (USA/UK/Canada) and Siemens (Germany) make Protection Relay and Substation Automation System (SAS) are already existed in PGCB's System and their performance is proven, only Manufacturer's Authorization letter among the Qualification Criteria of clause 2.6 of Section 3 of volume 1 of 3 of the Bidding Document is required to be submitted with the bid of the bidders who choose to propose Relay & SAS from these proven

manufacturers. Acceptance of any other Relay, control system and SAS with similar characteristics shall have to fulfil the Qualification Criteria of clause 2.6 of Section 3 of volume 1 of 3 of the Bidding Document.

5.2.2 The protection shall be sufficiently sensitive to cater for the minimum fault level condition. This will be advised later. The protection shall also be suitable for a system fault level equal to the switchgear rating as mentioned in section 1 of this specification for all voltage system. All current transformer design shall be based on these fault levels.

5.2.3 All relays shall operate correctly within system frequency limits of 47Hz to 51Hz.

5.2.4 Installation, testing and commissioning of Control, protection and metering system shall be done by the Manufacturer(s) Engineer(s).

5.2.5 All the Auxiliary relays (Contactor, TCS, Tripping relays, thermostat, humidity controllers etc.) used for protection scheme shall be of Europe/USA origin or from any eligible country with equivalent quality.

5.2.6 Since some of the above mentioned make, viz., ABB (Switzerland/Sweden), Alstom/GE (France/UK/USA), Siemens (Germany), SEL (USA), relay and control system is already existed in PGCB's System and their performance is proven, only Manufacturer's Authorization letter among the Qualification Criteria of sub-clause 2.5 of Section 3 of volume 1 of 3 of the Bidding Document is required to be submitted with the bid of the bidders who choose to propose Relay & SAS from these proven manufacturers. Acceptance of any other relay, control system and SAS with similar characteristics shall have to fulfill the Qualification Criteria of sub-clause 2.5 of Section 3 of volume 1 of 3 of the Bidding Document.

5.3 Fault Clearance Times

5.3.1 400kV, 230 kV, 132 kV and 33 kV systems overall fault clearance times (i.e. from fault initiation to arc extinction) shall not exceed the following:

Type of Fault		Maximum Fault Clearance Time			
Nominal system voltage between phases	kV	400	230	132	33
Substation and transformer fault	msec.	80	100	120	300
Line faults:					
Up to 72% of the line length (i.e. 90% of a distance relay zone 1 reach setting of 80% of the line impedance)	msec.	80	100	120	300
72% of 100% of the line length where (@) plus protection signalling time	msec.	100	130	150	300

5.3.2 These requirements must be fulfilled under all system conditions including maximum dc current offset and any time delay. Clearance within these times shall be achieved for all types of faults except high resistance earth faults detected by DEF protection or under circuit breaker failure conditions.

5.4 Arrangement of Facilities

- 5.4.1** Control and relay equipment shall be mounted on panels and cubicles as specified and shall be installed in permanent buildings on the substation sites. The order of the panels shall follow the sequence shown on the drawings. Sufficient protection from external disturbances must be established for the Control, Protection and SAS equipments. Control cables should be properly armoured; sealing must be provided at the entrance of the respective panel.
- 5.4.2** Panels provided as extensions or for erection in the same room as existing panels shall be of similar design and appearance to those existing. Equipment, meters, etc., mounted on such panels shall likewise be of style and scaling similar to the existing equipment. Characteristics of relays, etc., and all connections of equipment to be associated with existing equipment shall be such that they are fully compatible with and can operate satisfactorily in conjunction with the existing equipment. The characteristics and appearance of all such equipment shall be to the approval of the Engineer.
- 5.4.3** Backup Control panels shall incorporate all necessary control and indication facilities along with hardware based interlocks for the operation of the devices at the associated substation even in the case of failure of Substation Automation System. In addition, the substation may be remotely controlled and supervised from the National Load Dispatch Centre (NLDC) in Dhaka. Necessary NLDC integration must be performed by the contractor.
- 5.4.4** The Gateway system for communication to the NLDC shall be supplied under this contract including all necessary items like auxiliary switches, relays and changeover switches etc. All circuits provided under this contract whether or not they are subject to the system control requirements at the present time, shall be designed and constructed so that the standard facilities specified can be readily provided as required in the future.
- 5.4.5** The Contractor shall be responsible for ensuring the correct operation of the protective equipment and shall submit for approval recommended relay settings supported by design calculations for all protective equipment being supplied. The Engineer reserves the right to ask the Contractor to get the design calculations approved by the Manufacturer of the Protection equipment and/or get the confirmation for the suitability of the particular protective relay for the proposed application. In case the proposed Protective relay is not suitable for the proposed application the Contractor shall change to a suitable relay as recommended by the Manufacturer without any cost implications to the Engineer.
- 5.4.6** Protection facilities have to be arranged as shown in the Trip Matrix provided in the Bid document.

5.5 Multi-Core Cable Diagrams

Diagrams of communication arrangements will be made available to the Contractor who will be required to coordinate the provision of necessary multi-core cabling. This contract includes the preparation of cabling schematic diagrams, showing the approved routing of cores in the various cables, and detailed cable schedules and connection diagrams for all the cables associated with each item of equipment.

5.6 Test and Earthing Facilities

- 5.6.1** Each control or relay panels shall be provided with a copper earth bar of not less than 150 sq.mm Cross-section and arranged so that the bars of adjacent panels can be joined together to form a common bus.
- 5.6.2** The common earthing busbar of control and relay panels shall be connected to the main station earthing system via a copper earthing connection of not less than 150 mm².
- 5.6.3** Software for testing the protection & control devices shall be included in the scope of supply. In addition, for secondary injection testing of the protection & control devices, provision shall be made in the panel for current & voltage injection using standard test set and disconnecting type terminal blocks with facility for short circuiting of current transformer secondary circuit etc. by means of movement of links from their normal operating position, or any other testing arrangement approved by the Engineer.
- 5.6.4** Panel front mounted Test Terminal Blocks (TTB)/Test Sockets have to be provided for online testing of all Protective relays. Facility of online CT shorting, VT circuit isolation should be available in the TTB. 2 sets of associated Test Plugs should also be supplied for each substation under contract.

5.7 Protection Devices

- 5.7.1** Simplified arrangements of the main connections and protection for the various items of the substation are shown in Bid Drawing.
- 5.7.2** Protection equipment shall be designed and applied to provide maximum discrimination between faulty and healthy circuits. All equipment is to remain inoperative during transient phenomena which may arise during switching or other disturbances to the system.
- 5.7.3** Current transformers, where possible, are to be located so as to include the associated circuit breaker within the protected zone and shall be located generally as indicated on the schematic drawings included in this Specification.
- 5.7.4** Transformer Buchholz, winding temperature, oil temperature, tap changer protective devices and pressure relief devices are to be supplied under this contract, and all necessary interposing relays, tripping relays and cabling associated with these devices shall be supplied and mounted under this contract.

5.8 Relays

- 5.8.1** General: Relays shall be of approved types complying with IEC 60255 or British Standard 142 and 5992, Parts 1,2 and 3 as appropriate, fully tropicalized, and shall have approved characteristics. Relays designed identical to relays with a minimum of five years proven field experience will only be accepted. Supply record of proposed relays shall be furnished for the last five years. The Engineer will reject any design he considers unsatisfactory or having insufficient field experience. All the protective relays shall be numerical type only. Numerical relays shall be configured in such a way that at least 2 nos. relays shall be provided for each feeder.
- 5.8.2** The protection relays, shall be located in conventional panels and shall be flush mounted in dust and moisture proof cases and of the draw out type with rear connections.

- 5.8.3** Relays shall be of approved construction and shall be arranged so that adjustments, testing and replacement can be affected with the minimum of time and labour. Relays of the hand reset type shall be capable of being reset without opening the case.
- 5.8.4** Electrically reset tripping relays shall be provided where necessitated by the system of control, such as for those circuits subject to remote supervisory control.
- 5.8.5** Relay contacts shall be suitable for making and breaking the maximum currents which they may be required to control in normal service but where contacts of the protective relays are unable to deal directly with the tripping currents, approved auxiliary contacts, relays or auxiliary switches shall be provided. In such cases the number of auxiliary contacts or tripping relays operating in tandem shall be kept to the minimum in order to achieve fast fault clearance times. Separate contacts shall be provided for alarm and tripping functions. Relay contacts shall make firmly without bounce and the whole of the relay mechanisms shall be as far as possible unaffected by vibration or external magnetic fields.
- 5.8.6** Relays, where appropriate, shall be provided with LED or flag indicators, phase coloured where applicable. LED or Flag indicators shall be of the hand reset pattern and shall be capable of being reset without opening the case. Where two or more phase elements are included in one case, separate indicators shall be provided for each element.
- 5.8.7** All Relay settings shall be visible and readable without having to remove the relay front cover. It shall not be possible to amend relay settings with the front cover in place; other than over a serial link.
- 5.8.8** If a connector for local use is provided this shall be accessible only after removing the front cover. Where a port is provided for permanent connection to a modem or other peripheral equipment, remote access shall be password protected.
- 5.8.9** Relays which rely for their operation on an external DC supply shall utilise for this purpose the trip supply of the associated circuit breaker trip coil. This supply shall be monitored and an alarm provided in the event of failure.
- 5.8.10** Any auxiliary supplies needed shall be drawn from the main station batteries and not from separate internal batteries in the protection equipment.
- 5.8.11** Relays, whether mounted in panels or not, shall be provided with clearly inscribed labels describing their function and designation in addition to the general purpose labels.
- 5.8.12** Attention is practically drawn to the tropical climate and relay designs should be entirely suitable for duty under full tropical conditions.
- 5.8.13** To minimize the effect of electrolysis, relay coils operating on DC shall be so connected that the coils are not continuously energized from the positive pole of the battery.
- 5.8.14** Relay shall be suitable for operation on 110 V nominal, 121 V float DC systems without the use of voltage dropping resistors or diodes
- 5.8.15** Numerical protection shall be designed in such a way that in case of a failure of DC auxiliary infeed, the full information needs to be maintained at least 24 hrs. After a recovery of DC auxiliary infeed, the last information and alarms will be displayed and the alarm "failure of DC auxiliary infeed" released. The relay reset shall not erase the relay memory.
- 5.8.16** The Numerical protection functions shall be in the form of software such that additional or different functions, application specific logic etc. can be readily implemented without changes to the existing hardware. It shall be possible to programme/ parameterize by a portable computer (PC) all the numerical protective relays and the entire relay operating and configuring software and the portable

computers and other accessory equipment needed to communicate with the relays shall be provided.

5.8.17 All numerical relays shall be adequately protected against damage from incoming surge and shall meet relevant IEC, BS and ANSI SWC test standards. Relays shall utilize a DC-DC converter type regulated power supply to provide transient surge isolation between the station battery and protection equipment. Each DC supply shall be designed to protect it from high voltage and surge and provide electrically isolated contacts for annunciation.

5.8.18 In addition, to all equipment and components, the Contractor shall supply documents and calculations to prove the correct functioning of the equipment and he shall ensure and demonstrate that the setting range of relays and the operating limits of all equipment is suitable for the intended applications.

5.8.19 Electromagnetic Compatibility

5.8.20 In certain cases, e.g. distance protection, current differential etc., electronic relays, or devices utilising microprocessors are specified and electromagnetic devices will not be accepted.

5.8.21 Where such devices are required, they and the ancillary circuits connected to them, such as power supplies, current and voltage transformer secondaries, status or tripping or alarm circuits shall be designed to ensure that they are compatible for use in the hostile electrical environment found in an EHV substation.

5.8.22 Adequate steps, by means of suitable design, shall be taken to prevent Electromagnetic Interference (EMI) (generated by sources such as circuit breakers, disconnectors, lightning, radio or radar emissions, switching contactors in dc circuits etc.) or Electrostatic Discharges (ESD) from affecting relay performance or causing damage to components.

5.8.23 All relays offered must therefore have been type tested to meet the current requirements of IEC 60255 with respect to High Frequency disturbance, Fast Transients, Electrostatic Discharge, Radio Frequency Interference testing etc.

5.9 Overhead Line Protection

5.9.1 400kV, 230kV and 132 kV Transmission Line Protection

Protective devices for Main 1 and Main 2 overhead line protection are shown on Bid Drawing. These devices shall comply with the following. For 400KV transmission lines two sets of line differential relays shall be proposed which must be matched with the remote ends if necessary, remote end relays shall be also included in the scope of supply with necessary communication equipment.

5.9.1.1 Main 1 and Main 2 protection of 230 kV & 132KV line shall be of Line differential protection with back-up distance protection for short length or if the remote end already has line differential relay. Line differential protection is optional of Long and Medium length lines. Definition of Long, Medium and Short length line is base on Clause 5.2 of IEEE Std. C37.113™-2015. The Main & Back-up protection of 132 kV line shall be Line differential with full scheme distance protection or Distance protection alone (based on the criteria above) and Directional overcurrent & Earth fault protection respectively. Main 1 and Main 2 both protection of 230 kV line shall be Line differential with full scheme distance

protection or Distance protection alone (based on the criteria above). Both Main-1 and Main-2 protections should operate in conjunction with tele-protection channels over optical fibre for tele-protection schemes of distance protection. All relays shall be of numerical type. The philosophy of PSLD & Trip logics will be applied in all aspects.

- 5.9.1.2** Each set of protection will be energised from separate current transformers and shall have facilities for independently tripping duplicated circuit breaker tripping coils and initiating auto-reclosing, breaker failure protection, inter-tripping, alarms, fault location equipment, disturbance recorders etc. The Contractor shall ensure that the relay contacts used for initiation of auto reclosing shall have the same dwell time as the main tripping contacts to avoid any problems arising from contact racing with the auto reclose relay.
- 5.9.1.3** Separate elements shall be provided for phase and earth fault measurement. Separate elements shall also be provided for each zone. Phase and earth fault compensation features shall be incorporated to ensure accurate distance measurement for all types of fault and to allow for variation in the path of earth faults on the system.
- 5.9.1.4** The relay scheme offered shall be suitable for use in the permissive under-reaching, permissive overreaching, direct transfer trip, CB Echo logic, Weak End Infeed Echo logic, blocking and unblocking modes for Distance (21) and Directional Earth Fault (67N) functions. All these options shall be contained and selectable in the standard relay scheme. The relay should be applicable to all neutral ground possibilities and should be suitable for the protection of long, medium or short overhead lines or cables, double circuit lines, heavily loaded lines, lines with weak infeed etc.
- 5.9.1.5** To provide high speed tripping when a line terminal is open a 'signal echo feature' shall be provided, which is initiated when either the feeder disconnecter is open, or when the associated circuit breakers are open.
- 5.9.1.6** The Zone 1 elements will normally be set to approximately 80 per cent of the line impedance. They shall trip the local line circuit breaker.
- 5.9.1.7** The Zone 2 elements will be set to overreach the remote substation and in the case of permissive over-reaching mode operate in conjunction with teleprotection signalling channels to form a permissive over-reaching scheme. They shall also act as a back-up time delayed zone which trips the local circuit breaker. In the case of permissive under-reaching mode protection the overreaching Zone 2 unit will be used as the permissive element to permit instantaneous tripping of the local circuit.
- 5.9.1.8** The Zone 3 elements shall provide a further time delayed back-up zone.
- 5.9.1.9** Distance protection back-up zones shall also have the facility to trip the remote end circuit breaker(s) via a direct intertripping channel.
- 5.9.1.10** Partially cross polarized mho or polygonal impedance characteristics relays are preferred for Zones 1 and 2 for 3-phase and 2-phase faults but other characteristics will be considered. Quadrilateral characteristics with adaptive reactance measurement to avoid overreach or underreach for resistive faults with pre fault load are preferred for earth faults. The relays shall operate for faults in the direction of the protected line only. Under no circumstances shall they operate for reverse faults even when the voltage supplied to the relay falls to zero on all three phases nor shall they operate due to the transient response of the capacitive voltage transformers following reverse close-up faults if the protection zone is selected for forward region. Details of methods used for polarising the relays to deal with faults close to the relaying point shall be provided. Zone 3

shall be capable of being set as either directional or non-directional and shall be capable of being independently off set in both directions.

5.9.1.11 The reach of each zone and reverse element shall be individually adjustable by means of a multi-tap voltage transformer or other approved method. The characteristic angle shall be adjustable between approximately 40 and 80 degrees.

5.9.1.12 Where used in a permissive overreach transfer tripping scheme with weak infeed tripping the zone 3 unit may be set looking in the reverse direction. The reverse looking impedance/directional elements shall detect all reverse faults capable of being detected by the Zone 2 relay at the remote substation. Bidders shall explain how this is achieved.

5.9.2 Single pole tripping and auto-reclosing are being employed and the auto-reclosing scheme requirements are given in Section 5.11. The distance protection shall be suitable for such a scheme and the Contractor shall substantiate by calculation or other means that phase selective tripping will be achieved under the system conditions anticipated in the daily operation. The Contractor may request whatever information he requires for carrying out the necessary calculations.

5.9.2.1 Auto reclosing shall be capable of being blocked for

- i. any multi-phase fault
- ii. any Zone 2 or Zone 3 time delayed trip
- iii. Tele-protection channel out of service
- iv. DEF back up time delayed trip without teleprotection aided scheme.
- v. Switch on to fault.

5.9.3 The necessary circuitry shall be incorporated to inhibit the Zone 1 and Zone 2 phase fault elements when necessary during single phase to earth faults and during the single phase auto-reclose dead time. These features shall be selectable by links or switches. Provision shall also be made to ensure that the earth fault elements reset during the single phase dead time.

5.9.4 The protection sensitivity shall be shown to be adequate for the minimum fault level conditions. These will be advised to the Contractor at a later stage

5.9.5 Where fault resistance may be significant, the Contractor shall illustrate that the distance protection can cover such values taking fault current distribution and load conditions into account.

5.9.6 The operating time of each distance protection zone shall be substantially independent of fault current magnitude. The operating times shall be stated in the Schedule of Particulars and, in addition, curves shall be provided showing the effect of line and source impedance, fault position and operating current.

5.9.7 Under no circumstances shall any line protection operate because of normal system switching including de-energisation of the line.

5.9.8 A feature shall be incorporated to ensure instantaneous tripping in the event that the circuit breaker is closed onto a fault on a previously de-energised line.

5.9.9 Distance protection back-up Zone 2 and Zone 3 time delay setting ranges shall be 0.2 to 1.0 seconds and 0.5 to 3.0 seconds respectively.

5.9.10 A carrier receives signal extension timer with a delay on reset of 100 msec. shall be provided to ensure that relays at both ends of a parallel feeder circuit have sufficient time to trip for faults occurring in the end zones of the protected line.

5.9.11 A monitoring system shall be provided to supervise the voltage transformer supply to each set of distance protection. In the event of loss of one, two or three phases, the

monitoring system shall inhibit relay operation and initiate an alarm. The VT supervision unit associated with the distance relay shall also inhibit the DEF protection in the event of VT fuse failure.

- 5.9.12** All relays shall incorporate indicators to show the relay tripped, zone indication and the phase or phases faulted. Indication must not be lost in the event of a supply failure
- 5.9.13** Directional earth fault protection operating in a permissive overreach scheme shall be provided to cater for high resistance faults which cannot be detected by the distance protection. The same teleprotection signalling channel shall be used for the directional earth fault scheme and the distance protection scheme. An echo feature shall be included with the DEF Scheme and shall be subject to approval by the Engineer.
- 5.9.14** The directional relays shall be dual polarised i.e. polarised with zero sequence voltage and current. The relay sensitivity shall be adjustable between approximately 5 and 10% of rated current. A relay characteristic angle of 60 degrees is preferred but alternative angles will be considered. It is appreciated that because the 230 kV system zero sequence source is an auto transformer with a delta tertiary winding, that current polarising of a dual polarised relay is unreliable without careful analysis. The Contractor shall be responsible for determining whether such a current signal can be taken from the auto transformer neutral and safely used for polarising the relay within three months of being advised of all transformer impedance parameters.
- 5.9.15** The directional earth fault protection shall initiate three pole tripping. It must therefore include a short time delay to permit single pole tripping by the distance protection. Initiation of three pole reclosing following operation of a DEF aided trip shall be selectable by means of a switch.
- 5.9.16** Directional earth fault relays shall incorporate a back-up stage in addition to the aided tripping unit. The time delay range shall be 0.2 to 5.0 seconds or inverse time delayed with a characteristic to IEC 60255.
- 5.9.17** Neither the distance protection scheme nor the directional earth fault scheme shall mal-operate due to fault current reversal during sequential clearance of a fault on the parallel circuit.
- 5.9.18** The effect of zero sequence mutual coupling between the double circuit lines on the protection shall be described, together with any measures considered necessary to overcome this effect.
- 5.9.19** The distance protection time delayed back-up Zones 2 and 3 and the directional earth fault back-up stage shall inter-trip the remote station circuit breakers over direct inter tripping channels.
- 5.9.20** Auto reclosing shall not be initiated on receipt of direct inter-tripping signal. Direct inter-tripping shall also be initiated in the event of a 3 phase fault in any zone, or following a switch on to fault trip.
- 5.9.21** Distance relays shall be supplemented by power swing blocking relays. Power swing blocking relays shall be compatible with their appropriate distance relays, and for distance relays having offset mho zone 3 characteristics or starters shall comprise an offset mho characteristic which encompasses and is concentric with the distance relay impedance starter or zone 3 characteristic. Similarly, where it is possible to shape the zone 3 or starter characteristic the power swing blocking relay characteristic shall also be capable of similar shaping. Where zone 3 is set reverse looking the power swing blocking characteristic shall be set such that it encompasses the forward-looking zone 2 characteristic.

- 5.9.22** Facilities shall be provided to block zones 1, 2 and 3 of the distance relay from the power swing blocking logic as required.
- 5.9.23** Blocking logic shall be derived by determining the time taken for the apparent impedance of the power swing locus to pass from the characteristic of the power swing relay to the appropriate distance relay characteristic. Blocking shall not take place until the apparent impedance has passed through the two power swing characteristics and the set time delay has expired.
- 5.9.24** The associated time delay relay shall have a setting range of 50-250 ms.
- 5.9.25** Relays shall be of numerical design. Electromechanical relays will not be accepted. The Numerical relays shall be design with 16 bit Analogue to Digital converters, powerful Digital signal processors, CPU etc. The relay should have continuous self-supervision and diagnosis. A local display unit shall be provided on the front of the relay for measure and display, Distance to fault indication, diagnostics, etc. and also for acknowledging and resetting of latched outputs. The required software for setting and configuring the relay shall be provided with the relay and this man machine communication (MMC) shall be user friendly and should not require any special programming knowledge. It should be possible to do the settings off line and load the settings on to the relay with a standard portable PC with a fibre optic connection. A separate communication port shall be provided so that the distance relays can in future communicate with the Station monitoring system as well as easily be integrated into Station Control Systems. A PC with a man machine communication (MMC) software for setting of the relay shall be included in the scope of supply.
- 5.9.26** Reset times shall be low to ensure the associated distance relay reverts to its normal role as soon as possible following a power swing.
- 5.9.27** Power swing blocking shall be inhibited during the single pole dead time of an auto reclose cycle so that if a power swing develops during this period the distance protection can give an immediate three phase trip. The Bidder shall advise whether it is possible to extend the inhibition of the power swing blocking to cover a period immediately following auto reclosing so that if a power swing develops on reclosing onto a permanent fault a 3-phase trip would be permitted. The Bidder shall also advise whether power swing blocking can be inhibited if an earth fault occurs during a power swing.
- 5.9.28** If the associated VT supplies are lost due to VT fuse failure the power swing blocking relay shall not operate.
- 5.9.29** Where protection is supplied from multi-ratio current transformers, the lowest ratio will be used for the initial system configuration, when fault levels are low. The working ratio will be increased when the system expands and the fault levels and load transfers increase.

5.10 Busbar Protection

- 5.10.1** The busbar protection for 400kV (1 & 1/2 Breaker and Double Busbar scheme), 230kV & 132kV shall be low impedance type numerical relay capable of detecting all types of phase and earth faults under all system generation conditions. Busbar protection system should be distributed in principle. The protection shall be extensible to cover the final substation arrangements and Bidders shall state what extra material is required.

- 5.10.2** Each busbar having voltage levels of 230KV and above shall be protected with 2 (two) sets of Main and Redundant busbar protection system. Two sets of busbar protection should be from two different manufacturers.
- 5.10.3** The busbar protection shall meet the fault clearance time of 80ms for 400kV under all conditions and have the following features:
- 5.10.3.1** In case of 400kV busbar protection, two independent measurement, protection & tripping criteria shall be applied.
 - 5.10.3.2** One based on stabilized current differential algorithm and the other on directional current comparison and shall be capable of detecting three phase, phase-phase and phase to earth faults, under all system generation plant conditions.
 - 5.10.3.3** logics and close blocks for Busbar protection operation will be implemented as shown in PSLD & Trip logic and associated trip matrix.
 - 5.10.3.4** The operating time of the measuring relays shall not exceed 30msecs at five times the relay current setting.
 - 5.10.3.5** The busbar protection should be capable of feeding from different ratio of current transformers in different feeders. The working ratio will be selected on the basis of maximum load transfer in the same manner as the line current transformer ratios.
 - 5.10.3.6** The rated stability limit of the protection shall not be less than the switchgear short circuit rating.
 - 5.10.3.7** Stability against all external faults must be confirmed even in case of severe CT saturation.
 - 5.10.3.8** Automatic and continuous supervision of current transformer circuits shall be provided to give an alarm when the out-of-balance current reaches an undesirable value. Operation of differential current supervision element should take the defective protection zone out-of-service.
 - 5.10.3.9** The Contract shall include for all necessary current transformers, relay panels, marshalling boxes, isolating and shorting links, etc. 5 (five) nos selector switches have to be provided for enabling and disabling BBP (Busbar Protection), BFP (Breaker Failure Protection), EFP (End Fault Protection), Output contacts and All functions.
 - 5.10.3.10** Suitable voltage limiting devices shall be provided as necessary, including across the unused part of the CT secondary when tapings are employed.
 - 5.10.3.11** Full details of the scheme offered, together with performance figures for stability and sensitivity shall be provided.
 - 5.10.3.12** The numerical busbar protection shall be multi processor in structure, with extensive self-supervision, 16 bit analogue to digital converters, together with appropriate algorithms to provide phase segregated measuring principles and multi criteria evaluations before initialisation of trip commands. The bay units shall be fixed as close to the CTs as possible reducing the copper wiring to a bare minimum and thereby also reducing the CT burden and CT dimension.
 - 5.10.3.13** If the intercommunication between the bay unit and central unit by fibre optic cables, the required fibre optic cable and all necessary items shall be supplied, connected and commissioned by the Bidder. Fibre optic cables connected between panels have to be appropriately armoured, sealed and protected from external disturbances.
 - 5.10.3.14** Front mounted HMI should be provided with Central Unit and each Bay Unit of busbar protection system having facility of accessing all relevant measurements, alarms, tripping information and switching device information without connecting external computers.

5.10.3.15 Complete configuration including software and hardware capabilities should be available in BBP system for accommodating existing feeders as well as future feeders. No further engineering would be required during extension of future feeders, only installing new Bay Units should be sufficient.

5.10.4 Extension of existing busbar protection: The scope of work under this contract is to extend the existing busbar protection for new bays with the same equipment.

5.10.5 Conditions of Acceptance of Busbar Protection Systems Submitted on the Basis of Calculated Performance

The Contractor shall prepare for approval calculated performance data for differential busbar protection systems in lieu of heavy current tests, subject to the following:

- i) The rated stability limit shall be no less than the three-phase symmetrical breaking capacity of the associated switchgear.
- ii) ~~The overall fault setting for any type of fault shall be between 10% and 30% of the minimum fault current available. The minimum fault current available for a busbar fault will be advised later.~~
- iii) Current transformer knee point voltages shall not be less than twice the relay circuit setting voltage.
- iv) The maximum peak voltage across current transformer secondary wiring shall not exceed 3 kV under maximum internal fault conditions.
- v) Associated current transformers shall be Class X or 5P, low reactance type. Split core type current transformers will not be accepted.
- vi) The Contractor shall submit for the Engineers approval a design report detailing the protected equipment, design parameters of associated current transformers, details of connections and burdens between current transformers and relays, details of the relay circuits and performance calculations.

5.11 Circuit Breaker Failure Protection

5.11.1 Breaker failure protection shall be fitted to all 400kV, 230 kV and 132 kV circuit breakers of the substation. Each CB having voltage level of 230KV and above will be equipped with 2 (two) nos main and redundant Breaker Failure Protection. The breaker failure protection on a circuit breaker shall be initiated by all the other protection devices which normally initiate tripping of that breaker including the receipt of a direct inter-tripping signal from a remote line end. In the event of the circuit breaker failing to open within a pre-selected time, the breaker failure protection shall issue a re-trip to the same Circuit Breaker through an alternative path of the initially issued trip signal. If the Circuit Breaker fails to open even after receiving the re-trip signal, the BFP will initiate tripping to ~~all adjacent~~ circuit breakers of all connected sources. It shall also incorporate provision for initiating tripping of any remote infeeds, via direct inter-tripping channels over optical fibre communication link or power line carrier circuits.

5.11.2 On the other hand, BFP remote tripping from the remote infeeding end will be received by the local end relays to issue tripping to local end CBs.

5.11.3 In the case of 400kV, 230 kV and 132 kV circuit breaker failure protection, the position of each circuit breaker shall be monitored by a current check relays fed from

the protection current transformers as shown on the drawings. The relays shall have an operating time of approximately 10 msec. and a consistent reset time of less than 15 msec. The relays shall be capable of remaining in the operated position continuously and of carrying twice the circuit rated current continuously.

- 5.11.4** The operating time from initiation to back-up tripping output shall be selected by means of duplicated timers with a setting range of 50-500 msec.
- 5.11.5** The timers shall be of a modern design to minimise overtravel. With the approval of the Engineer the busbar protection trip circuits may be employed for circuit breaker fail back-up tripping.
- 5.11.6** In the event that a circuit breaker is unable to trip due to low gas pressure, low hydraulic oil pressure etc. the associated alarm shall be arranged to by-pass the breaker fail time delay. The breaker fail relay/scheme shall be designed to accept this input.
- 5.11.7** Operation of the breaker fail protection shall block manual and automatic reclosure of the associated circuit breaker. Breaker failure protections inbuilt in distance / transformer relays will not be accepted.
- 5.11.8** Breaker Failure Protection will be implemented as a built-in function of Busbar Protection system for Double Busbar bus arrangement. Same will be applicable for Bus side Circuit Breakers of 1 and half CB bus arrangement. Stand-alone Breaker Failure Protection relay can be provided for Tie CB of 1 and half CB bus arrangement depending on manufacturer's practice.

5.12 End Fault Protection

- 5.12.1** Blind zone between Circuit Breaker and Current Transformer needs to be protected with End Fault Protection where overlapping protection zones are not formed due to CT location.
- 5.12.2** End Fault Protection will be implemented as a built-in feature of busbar protection system.
- 5.12.3** Tripping will be issued to remote infeeding end either through direct inter-tripping (in case of transformer) or through Tele-protection channel (in case of OHL) with selectable time delay if EFP is detected.

5.13 Auto-Reclosing Scheme

- 5.13.1** Three pole and/or single pole, single shot repetitive auto-reclosing equipment, shall be provided for the overhead line circuit breakers.
- 5.13.2** Reclosure shall be initiated following tripping by either main protection operating in Zone 1 or in conjunction with a tele protection receive signal or DEF with teleprotection aided scheme. Selection facilities shall also be provided to enable or block three pole delayed auto-reclosing following operation of the directional earth fault protection aided trip output. Re-closure shall not be initiated in the event of a three phase fault, nor any type of fault in the second or third back-up zones, nor when a direct inter-tripping signal is received, nor when the circuit breaker is closed onto a fault on a previously de-energised line, nor when the DEF back-up protection operates nor if the carrier channel is out of service nor O/C & E/F protection operated nor voltage protection operated.
- 5.13.3** The following modes of operation shall be selectable by means of a switch or switches or programmable.

(a) Single pole, high speed, auto-reclose: Auto-reclosure shall only be initiated in the event of a single phase to earth fault. All other types of faults shall result in three phase tripping without auto-reclosing.

(b) Three pole delayed reclosing: Delaying reclosing shall only be initiated in the event of a single phase or two-phase fault. Three phase faults shall result in tripping without auto-reclosing.

(c) Single pole, high speed and/or three phases delayed, auto-reclosing as appropriate.

Single pole, high speed auto-reclosing shall be initiated only in the event of a single phase-earth fault and delayed reclosing initiated in the event of a two-phase fault. Three phase tripping without re-closing shall take place for three phase faults.

5.13.4 If a second earth fault occurs during the single pole auto-reclose dead time, and the selector switch is in the single and/or three pole reclosing mode three phase tripping with subsequent delayed three pole auto-reclose shall take place. If the auto-reclose selector switch is in the single pole reclose mode, three phase tripping with lockout should follow. Any auxiliary relays required to meet this logic shall be deemed to be included.

5.13.5 The high speed and delayed reclosing dead times have to be coordinated with the equipment being provided at the remote substation. Tentative ranges are, as follows:

- High speed single pole reclose dead time: 0.3 to 3 seconds.
- Delayed three poles reclose dead time: 3 to 30 seconds.

Bidders shall state available ranges.

5.13.6 The reclaim time i.e. the time period following the automatic reclosing of the circuit breaker, during which any further fault results in three phase tripping and lockout, shall be chosen to match the duty cycle of the circuit breakers, assuming the shortest available dead time is chosen. The reclaim time shall, however, not be less than five seconds, and the reclaim timer range shall extend to 180 seconds. (The reclaim time commences at the instant the reclose command is given to the circuit breaker and, therefore, includes the circuit breaker closing time).

5.13.7 The closing command shall be limited to two seconds, after which time the reclosing equipment shall be automatically reset without resetting the reclaim timer. The reclosing equipment shall also reset if dead line check or synchronism check conditions are not satisfied within a predetermined time of the check relays being energised.

5.13.8 A counter shall be provided to record the number of reclosures and lockout after a pre-selected number of reclosures has been reached.

5.13.9 The rated duty cycle of the circuit breaker as defined in IEC 60056 (and subsequent amendments) states that following an initial trip and auto reclosure a further reclosure is not permitted for a further 3 mins.

5.13.10 Auto-reclose functions have to be provided in Main-1 and Main-2 relays for voltage levels of 230kV and above. Main-1 line protection relay has to be selected as master for auto-reclose. A/R function of Main-2 relay will be active in case of unhealthiness of Main-1 relay for avoiding duplicated command. In case of 1 and half CB bus arrangement, A/R will be issued to Bus side CB initially. A/R reclose of Tie CB will be issued after successful reclosing of Bus side CB. Alternatively, A/R will be issued to Tie CB initially if the Bus side CB remains open beforehand.

Auto-reclose function will be activated in Main relay only for 145kV.

- 5.13.11** Reclosing schemes shall include voltage monitoring and check synchronising relays as appropriate.
- 5.13.12** Dead line check relays shall monitor the condition of the line and busbar and permit three pole reclosing only when the line is de-energised and the busbar is energised. The line is considered to be de-energised when the voltage is less than twenty percent of rated voltage, and the busbar is considered to be energised when the voltage is greater than eighty percent of rated voltage.
(A signal shall be provided from the dead line check relays for interlocking of the line earth switches to prevent the switches being closed onto a live line).
- 5.13.13** When a voltage is present on both sides of a circuit breaker, the synchronism check relay shall monitor the magnitudes of the two voltages across the open circuit breaker, and the phase angle and slip frequency between these voltages. Closing shall only be permitted when these are within prescribed limits.
- 5.13.14** Check synchronising relays shall comply with the requirements of Clause 5.24. 1. The same relays may be used as for manual closing.

5.14 Overcurrent and Earth Fault Protection

- 5.14.1** The overcurrent and earth fault relays shall be fully Numerical and have multi characteristics (inverse, very inverse, extremely inverse) to IEC 60255. Over-current and Earth-fault protections will be implemented as back-up protection of the main feeder protections for line and transformer feeders. The functions will act as main protection for Bus Coupler feeders.
- 5.14.2** In the case of underground line circuits relays should have a reset ratio greater than 95% to enable settings to be made which are close to the circuit emergency rating. The relay contacts must close at a current equivalent to 110% of the setting and relay overshoot must not exceed 50 msec.
- 5.14.3** Over-current and earth fault relays shall trip via the CB duplicate trip coils.
- 5.14.4** Relays shall be thermally rated such that the operating time of the relay at the highest practical current levels on any combination of current and time multiplier settings shall not exceed the thermal withstand time of the relay. The Contractor shall provide copies of type test reports to show that this requirement has been met.
- 5.14.5** Directional back up over-current and earth fault relays shall be provided for underground Cable, Line and Transformer feeders and the directional elements shall be voltage polarised.
- 5.14.6** Directional units for directional overcurrent protection shall be quadrature connected with a relay characteristic angle setting of 30° or 45° current leading voltage.
- 5.14.7** Directional units for directional earth fault back up protection shall employ residual voltage quantities and the relay characteristic angle be variable 0°, 45° and 60°, current lag.
- 5.14.8** The nominal operating boundary shall be $\pm 90^\circ$ from the relay characteristic angle and the operating time of the directional unit shall not exceed 20 ms at the relay characteristic angle.
- 5.14.9** The relay shall be capable of operating correctly when both the operating current and polarising voltage quantities are 1% of rated values at an angle equal to the relay characteristic angle.

- 5.14.10** The residual polarising voltage for earth faults may reach 190.5 volts and therefore it should withstand this value continuously. The continuous withstand current should be no less than twice rated current.

5.15 Coupling Bay Protection

- 5.15.1** The Coupler bay shall be provided with overcurrent instantaneous trip relay protection (50/50N) and overcurrent time delay relay protection (51, 51N). Relays shall comply with the requirements of clause 5.14.

- 5.15.2** All trip-signal of OHL and transformer feeder protection shall be transferred to the coupling breaker in case the feeder breaker is bypassed and the feeder is protected by the coupling-bay circuit breaker. This shall be provided by auxiliary relay, not by auxiliary contacts of the circuit breaker by-pass isolator.

5.16 Transformer Protection

5.16.1 Biased Differential Protection

- 5.16.1.1** The transformer differential protection shall be fully numerical design with 16 bit Analogue to Digital converters, powerful Digital signal processors, CPU etc. The relay should have continuous self-supervision and diagnosis. A local display unit shall be provided on the front of the relay for measure and display, Trip indications, diagnostics, etc. and also for acknowledging and resetting of latched outputs. The required software for setting and configuring the relay shall be provided with the relay and this Human Machine Interface (HMI) shall be user friendly and should not require any special programming knowledge. It should be possible to do the settings off line and load the settings on to the relay with a standard portable PC with a fibre optic connection.
- 5.16.1.2** Overall differential protection shall be of the biased differential type and capable of detecting phase and earth faults.
- 5.16.1.3** Separate facilities shall be provided to enable bias and operating settings to be adjusted. The minimum operating setting shall not be greater than 20 per cent of the rated full load current of the transformer.
- 5.16.1.4** The protection shall be designed to ensure stability on any transformer tap position under maximum through fault conditions with maximum d.c. offset even in case of severe CT saturation. An infinite source is to be assumed and the through fault current calculated using the transformer impedance only.
- 5.16.1.5** Correction for matching transformer vector groups and main CT ratio's for Transformer Differential protection shall be performed within the relay without the use of external interposing-transformer.
- 5.16.1.6** The relay characteristics should include unrestrained tripping without checking any restraining quantities or harmonics.
- 5.16.1.7** The relays shall have magnetising inrush current restraint of the second harmonic or other approved means. All necessary interposing current transformers shall be provided under the contract.

5.16.2 Restricted Earth Fault Protection

5.16.2.1 Where specified, or shown on drawings, transformer windings and connections shall be protected by restricted earth fault protection. Two (two) separate Restricted Earth Fault (REF) Protections have to be established for 3 (three) winding Transformers operating in voltage level 230kV or above. 1 (one) will be low impedance type having restraining characteristics and stability against heavy through fault even in case of severe CT saturation. Low Impedance type REF protection can be embedded in Main-1 Transformer differential relay.

5.16.2.2 The 2nd REF protection will be of high impedance type with necessary protection against over voltages. For reliability reasons the restricted earth fault relay shall be separate from the transformer differential relay.

5.16.2.3 2 (two) winding Transformers and transformers operating in 132kV may have only 1 (one) REF with low impedance type and embedded in Main-1 transformer differential relay having operating characteristics described above.

5.16.2.4 33kV winding of Earthing transformer (if any) will also be protected with low impedance type REF protection.

5.16.2.5 Relays shall have maximum sensitivity and minimum operating times consistent with stability for faults outside the protected zone and on magnetising inrush surges.

5.16.2.6 The rated stability limit shall not be less than the maximum current available for an external fault. This shall be taken as 16 times the rated current of the protected winding of the power transformer, or any other value agreed by the Engineer.

5.16.2.7 For the purpose of calculations it shall be assumed that any neutral earthing impedance is short circuited.

5.16.2.8 The Contractor shall prepare for approval calculated performance for instantaneous high impedance restricted earth fault protection in lieu of heavy current tests, except:

i) The rated stability limit shall be as specified above.

ii) The fault setting shall be as specified below.

(a) When the transformer winding is connected to a solidly earthed power system, the fault setting shall be between 10% and 60% of the rated current of the winding. When the transformer winding has more than one rating, the setting shall be based on the lower rating.

(b) When the protected transformer is not connected to a solidly earthed power system the fault setting shall be between 10% and 25% of the minimum current available for an earth fault at the transformer terminals.

5.16.3 Transformer Back-up Over-current Protection

Three-pole inverse time back up overcurrent and earth fault protection shall be provided as shown on the drawings. This shall comply generally with Clause 5.14 but in addition the overcurrent elements shall also be a two stage device. Stage 1 will comprise the inverse time unit and stage 2 will comprise an additional definite time unit with a setting range of 50 msec. - 5 secs.

Over-current and earth-fault elements should have selectable operating characteristics as shown in PSLD & Trip logic.

5.16.4 Gas Pressure (Buchholz) Protection

5.16.4.1 Power transformers and earthing transformers shall be fitted with Buchholz devices under this contract. The Buchholz device will be of the two element type giving operation under gassing and under surge conditions.

5.16.4.2 All necessary flag indication, tripping relays and alarm relays associated with this protection shall be provided, mounted and connected under this contract.

5.16.5 Oil and/or Winding Temperature

5.16.5.1 Transformers will be provided with oil and/or winding temperature protection under this contract. These will be of the two stage type with adjustable settings giving alarm and trip facilities.

5.16.5.2 All necessary flag indication, tripping relays and alarm relays associated with this protection shall be supplied and connected under this contract.

5.16.6 Low Oil Level and Pressure Relief Devices

5.16.6.1 Transformers shall be provided with low oil level with contacts for the purpose of providing remote alarm. Transformers shall also be provided with a pressure relief device with contacts for purposes of remote alarm and trip function.

5.16.6.2 The alarm relays associated with these devices shall be supplied and connected under this contract.

5.16.7 Tap Changer Oil Surge

5.16.7.1 Transformers will be provided with an oil surge or pressure operated device having contacts for purposes of remote alarm and trip.

5.16.7.2 A relay associated with this device shall be supplied and connected under this contract.

5.16.7.3 All necessary flag indication, tripping and alarm relays associated with tap change oil surge shall be provided.

5.16.8 Transformer Mechanical Protection arrangements

All mechanical protection of Transformer will be established either through Main-1 and Main-2 protection relays and through Lock-out type tripping relays with necessary flag and indication. The protections which are established with Main-1 and Main-2 relays, tripping and alarm signals from all devices have to be terminated to both relays for assuring redundancy.

5.16.9 Tripping Relays

5.16.9.1 All tripping relays, where specified shall be of the heavy duty type suitable for panel mounting. The trip relays of the offered numerical protections shall be directly capable of tripping the breaker coils. It shall not be required to add additional trip relays

5.16.9.2 Trip relay contacts shall be suitably rated to satisfactorily perform their required duty and relay operating time shall not exceed 5 ms. from initiation of trip relay operating coil to contact close.

- 5.16.9.3** Where specified latching type relays shall have hand or electrically reset contacts and hand reset flag indicators. Resetting of the flag indicator and the contacts shall be possible without having to open the relay case.
- 5.16.9.4** Tripping relays shall operate when the supply voltage is reduced to not higher than 30% of nominal battery voltage. It shall not operate for wiring leakage currents and discharge of wiring capacitance
- 5.16.9.5** 400kV, 230 kV and 132 kV circuit breakers are equipped with two trip coils. One tripping relay shall initiate tripping via one trip coil and the other tripping relay via the second trip coil.

5.17 DC Auxiliary Voltage Operating Range

DC operated relays, coils, elements, etc. will be operated from a 110V rated dc. battery, which under float charging conditions operates at about 125V. DC operated relays coils elements etc. shall be suitable for operation over a voltage range of 66V to 143V. i.e. 110 - 40% + 20%.

DC automatic changeover scheme has to be provided in each control & protection panel. Main-1 relays, Trip Circuit-1, Lock-out relay-1 should be connected to DC-1 and Main-2 relays, Trip Circuit-2, Lock-out relay-2 should be connected to DC-2 in normal condition. In case of failure of one DC system, the other system will automatically take care of the devices under the failed one.

Similarly for Control Panel, BCU will be supplied from DC-1 and Mimic/Emergency Control will be supplied from DC-2 in normal condition. DC changeover will be implemented as stated above.

DC supply of each panel will be taken directly from DCDB through separated MCB. DC looping among panels will not be accepted.

5.18 Tele-protection Signalling

Details of protection initiation and various permissive and direct inter-tripping signals are as specified in Section-14, of Vol. 2 of 3.

5.19 Digital Fault and Disturbance Recorder (DFDR)

- 5.19.1** The DFDR shall be delivered only for all new 400/230/33kV, 400/230/132kV, 400/132 kV and strategically important 132/33kV substations.
- 5.19.2** For the purpose of standardization, the DFDR to be supplied under this project shall be from Qualitrol (Belgium/UK), SIEMENS (Germany) , SEL (USA) or equivalent.
- 5.19.3** Installation, testing & commissioning of the DFDR shall be done by the DFDR Engineer(s) of the DFDR Manufacturer(s).

- 5.19.4** Since some of the above mentioned make, viz., Qualitrol (Belgium/UK), SIEMENS (Germany), SEL (USA) DFDR is already existed in PGCB's System and their

performance is proven, only Manufacturer's Authorization letter among the Qualification Criteria of sub-clause 2.5 of Section 3 of volume 1 of 3 of the Bidding Document is required to be submitted with the bid of the bidders who choose to propose DFDR from these proven manufacturers. Acceptance of any other DFDR with similar characteristics shall have to fulfill the Qualification Criteria of sub-clause 2.5 of Section 3 of volume 1 of 3 of the Bidding Document.

5.19.5 The DFDR shall have the following features:

- 5.19.5.1** The equipment shall be an independent stand-alone system to monitor analogue and digital signals from all 400kV, 230 kV & 132 kV feeders, including transformer and bus coupler bays that require to be monitored.
- 5.19.5.2** The Manufacturer shall prove the system's reliability and good site performances by providing substantial evidence of the systems already installed and commissioned for at least a duration of 5 years, accompanied by the customer's recommendations and type test reports from internationally acclaimed laboratories.
- 5.19.5.3** The DFDR system shall be modular in design for easy expansion, upgrade and maintenance.
- 5.19.5.4** The acquisition system or its storage unit shall not be based on a PC platform.
- 5.19.5.5** The independent DFDR system shall be equipped with a minimum of sufficient numbers of signals per bay as tabled below and shall be suitable for AC/DC measurement without any hardware changes.

Voltage Level	Input Type	Type of Feeder/System	Number of Inputs per Feeder/System
400kV	Analog	Line feeder	4 currents + 4 voltages = 8 in total
		Transformer feeder (400/230/33kV or 400/132/33kV)	4 currents + 4 voltages = 8 in total
		Bus Coupler feeder (for Double Busbar)	4 currents
		Busbar Protection System	4 voltages
		DC System	2 voltage
	Digital	Line feeder	36
		Transformer feeder (400/230/33kV or 400/132/33kV)	30
		Reactor feeder	16
		Tie section (for 1 and half bus arrangement)	7
		Bus Coupler feeder (for Double Busbar)	12
		Busbar Protection System	16
230kV	Analog	Line feeder	4 currents + 4 voltages = 8 in total
		Transformer feeder (230/132/33kV)	4 currents + 4 voltages = 8 in total
		Transformer incoming feeder (400/230/33kV or 400/132/33kV)	4 currents + 4 voltages = 8 in total
		Bus Coupler feeder (for Double	4 currents

Voltage Level	Input Type	Type of Feeder/System	Number of Inputs per Feeder/System
400kV	Analog	Line feeder	4 currents + 4 voltages = 8 in total
		Transformer feeder (400/230/33kV or 400/132/33kV)	4 currents + 4 voltages = 8 in total
		Bus Coupler feeder (for Double Busbar)	4 currents
		Busbar Protection System	4 voltages
		DC System	2 voltage
	Digital	Line feeder	36
		Transformer feeder (400/230/33kV or 400/132/33kV)	30
		Reactor feeder	16
		Tie section (for 1 and half bus arrangement)	7
		Bus Coupler feeder (for Double Busbar)	12
		Busbar Protection System	16
		Busbar)	
		Busbar Protection System	4 voltages
		DC System	2 voltage
	Digital	Line feeder	34
		Transformer feeder (230/132/33kV)	28
		Transformer incoming feeder (400/230/33kV or 400/132/33kV)	8
		Tie section (for 1 and half bus arrangement)	5
		Bus Coupler feeder (for Double Busbar)	12
		Busbar Protection System	8
132kV	Analog	Line feeder	4 currents + 4 voltages = 8 in total
		Transformer feeder (132/33kV)	4 currents + 4 voltages = 8 in total
		Transformer incoming feeder (230/132/33kV)	4 currents + 4 voltages = 8 in total
		Bus Coupler feeder	4 currents
		Busbar Protection System	4 voltages
		DC System	2 voltage
	Digital	Line feeder	26
		Transformer feeder (132/33kV)	24
		Transformer incoming feeder (230/132/33kV)	8
		Bus Coupler feeder	8
		Busbar Protection System	8

5.19.5.6 The system shall be equipped to monitor, detect and record simultaneously fast transient faults (short-term) and slow phenomena disturbances (long-term) like

power swing, frequency variation, voltage drop, etc., covering all the required feeders.

5.19.5.7 DFDR must comply all requirements stated in attached GTP of DFDR.

5.19.5.8 The graphical data should be recorded for all feeders simultaneously (snap shot image). The recording should contain the data prior to the event and after the event, including the dynamic length of the event / fault without any alterations.

5.19.5.9 The system should possess a library of sensors (triggering criteria), which should be selected by the user and shall be able to detect and record various type of incidents. The system shall be able to detect incidents by the selected starting criteria and should be able to produce a record.

5.19.5.10 The recordings shall contain the graphical data of physical inputs (voltage, currents, digitals) and virtual inputs (e.g. frequency, dp/dt, dq/dt (3 phases / single phase), RMS values etc.).

5.19.5.11 The DFDR shall be able to communicate with local and / or remote master stations, using master communication and analysis software. This software should permit the user either locally or remotely to download the recorded data, to ascertain the system's operational status, to change parameters, etc.

5.19.5.12 Master communication should be able to communicate via RS 232 (direct connection), through modem (dial-up telephone line) and LAN (Ethernet (TCP / IP) - IEEE 802.3) networking.

5.19.5.13 The DFR shall perform the following functions:

- fault location (including impedances and report),
- graphical display of data,
- phase measurement & display,
- transient fault recording,
- dynamic swing recording,
- harmonics' measurement & display,
- integrated SER function,
- calculated channels etc.

5.19.5.14 The system shall be able to calibrate at site, and the required menu-driven software and other required accessories shall be supplied along with a notebook computer, colour printer etc.

5.19.5.15 The system shall be equipped for time synchronization by the external GPS clock receiver for real time synchronizing (including antenna). GPS shall be capable of synchronizing PMU .

5.19.5.16 Local printing facility shall be provided with the system.

5.19.5.17 The master station (a latest version of PC) and the relevant software shall be supplied with the equipment for analysis and communication.

5.19.5.18 Power quality monitoring shall be made available for at least 4 feeders. Continuous monitoring (periodical recording) shall be available for all feeders.

5.19.5.19 If more than one Central Processing Unit is used for DFDR, configuration has to be done in such a way that records from all feeders will be stored in case of triggering any signal.

5.19.5.20 In addition to above, manufacturer shall provide warranty for its product at least for 5 years.

5.19.5.21 DFDR must be integrated with central master station located in Dhaka. Necessary hardware, software and license must be supplied for integrating the DFDR central Master station.

5.19.5.22 Phasor measuring unit (PMU) functionality shall be provided, which can be an integrated feature of DFDR or standalone IED.

5.19.5.23 Separate panel must be supplied for DFDR IPC or working station.

5.19.6 Extension of the existing DFDR: The scope of work under this contract is to extend the existing DFDR system for new bays. All necessary input and output (both digital & analogue) shall be provided as per the existing bays.

5.20 Travelling Wave Fault Locator (TWFL)

5.20.1 All line of 400kV voltage level or above shall be equipped with Travelling Wave Fault Locator (TWFL) for determining accurate fault location. The TWFL shall be suitable both for Single ended & Double ended application. For achieving double ended application necessary equipment & panel for the remote end Substation must be supplied. For LILO transmission lines TWFL shall be matched with remote end substation.

5.21 Tripping Relays

All tripping relays, where specified, shall be of high-speed (preferably 5 ms), high-burden, heavy-duty (larger than 150W) type and shall be suitable for panel mounting. Relays shall comply with the requirements of attached GTP. The relay used shall be of USA/Europe/Japan origin or other eligible countries with equivalent quality.

5.22 Protection Settings

5.22.1 Relay settings with calculation for all unit-type protective schemes shall be submitted to the Engineer and Employer prior to commissioning of any plant for approval. Settings shall also be provided for those relays and other equipment provided under this section of the contract which do not require an intimate knowledge of existing relay settings e.g. circuit breaker fail relays. Detailed calculations shall be provided supporting all recommended settings.

5.22.2 Computer Aided Setting Calculation shall be performed by the contractor and submit to the Engineer and Employer for approval. Software used for simulation shall be acceptable to & used to by PGCB. Hence, Contractor is requested to consider this software for simulation. Other software is also acceptable with the consent & approval of Employer. Contractor shall submit soft copy files of software for review & approval from Employer. A Power point demonstration is to be foreseen by the contractor for final approval.

5.22.3 Any additional information needed by Contractors should be requested.

5.23 Substation Automation System

5.23.1 Scope of Supply

- 5.23.1.1** This specification covers the design, manufacture, inspection, testing at the Manufacturer's works, erection and commissioning of a substation automation system, as shown in drawing of this technical specifications & described in the following sections, to control and operate the 400kV, 230 kV & 132 kV grid substation.
- 5.23.1.2** This describes the facilities required to provide the control of plant and system within a substation and outlines the facilities to be provided on site, interface requirements and performance criteria.
- 5.23.1.3** The substation automation system (SAS) shall comprise full station and bay protection as well as control, monitoring and communication functions; it shall provide all functions required for the safe and reliable operation based on IEC 61850 standards. It shall enable local station control via PC by means of a human machine interface (HMI) and control software package, and shall perform the necessary system control and data acquisition functions. It shall include two (2) communication gateways to NLDC, inter-bay bus, intelligent electronic devices (IED) for bay control and protection as shown in the enclosed general system architecture drawing.
- 5.23.1.4** The communication gateway shall secure control from and information flow to remote network control centres. The inter-bay bus shall provide independent station-to-bay and bay-to-bay data exchange. The bay level intelligent electronic devices (IED) for protection and control shall be directly connected to the instrument transformer and trip/close coils in the switchgear without any interposing equipment and perform control, protection, and monitoring functions subject to a detail proposal approved by the Employer.
- 5.23.1.5** The Contractor will have the option to choose different types of communication networks for the bay level and the process level based on IEC 61850. However, network topology and access mode shall be clearly indicated. The availability shall be maintained with suitable topology of ring, star or bus. The physical medium of those shall be glass fibre optics.
- 5.23.1.6** The IEDs for protection and control functions shall maintain high availability and reliability together with bay independence through extensive self-supervision and state-of-the-art technology. All IEDs shall be directly connected to the IEC 61850 bus and shall use only the IEC 61850 protocol for communication. No proprietary protocols shall be used. The SA system must have interoperability between IEDs of different manufacturers. Such shall be verified by test and submitted along-with the bid. The interoperability feature of SA must be verified during FAT also. System not having interoperability feature shall not be accepted.
- 5.23.1.7** The system shall be capable of having its computing power increased in the future through the addition of additional computing systems.
- 5.23.1.8** The system design life shall be not less than 20 years.
- 5.23.1.9** The capacity of the SA system shall be sufficient for the ultimate development of the substation as set out in the project requirements.
- 5.23.1.10** The SA Supplier shall demonstrate that the proposed system has been designed, installed and commissioned in accordance with the IEC 61850 standard and shall provide evidence of satisfactory service experience during the past 5 years.
- 5.23.1.11** The SAS shall have option for integration of Transformer Fire Prevention/Protection system integration. Necessary system configuration and switches shall be available for the said work.

5.23.2 Extension of existing SAS: The scope of work under this contract is to extend the existing SAS system for new bays. All necessary input and output shall be provided as per existing bays.

5.23.3 Compliance with Standards

For design and type-testing of the protection and control equipment, the following standards shall apply:

5.23.3.1 General List of Specifications

• IEC 60255:	Electrical Relays
• IEC 60038:	IEC Standard voltages
• IEC 68068:	Environmental testing
• IEC 60664:	Insulation co-ordination for equipment within low-voltage systems
• IEC 61850:	Standard for Substation integrated protection and control data communication

5.23.3.2 Detailed List of Specifications

• IEC 60068-2-3:	Test Ca: Damp heat steady state
• IEC 60068-2-30:	Test Db and guidance; Damp heat, cyclic
• IEC 60255-11:	Measuring relays and protection equipment
• IEC 60255-22:	Electrical disturbance tests for measuring relays and protection equipment:
• IEC 60255-22-1:	1 MHz burst disturbance test
• IEC 60255-22-2:	Electrostatic discharge test
• IEC 60255-22-3:	Radiated electromagnetic field disturbance test
• IEC 60255-22-4:	Fast transient disturbance test
• IEC 60255-11:	Interruptions to and alternating component (ripple) in D.C. auxiliary energising quantity to measuring relays
• IEC 60255-6:	Measuring relays and protection equipment
• IEC 60255-21:	Vibration, shock, bump and seismic tests on measuring relays and protection equipment:
• IEC 60255-21-1:	Vibration tests(sinusoidal)
• IEC 60255-21-2:	Shock and bump tests
• IEC 60255-21-3:	Seismic tests
• IEC 60255-0-20:	Contact performance of electrical relays
• IEC 60870-3 class 2:	Digital I/O, Analogue I/O dielectric tests
• IEC 60801-5/class 3:	digital I/O Surge withstand test
• IEC 60870-3/class2:	Radio interference test
• IEC 60801-4/4:	Transient fast burst test
• IEC 60801-2/4:	Static discharge
• IEC 60801-3/3:	Electromagnetic fields

5.23.4 Design and Operating Requirements

- 5.23.4.1** The SAS shall be suitable for operation and monitoring of the complete substation including future extensions. The offered products shall be suitable for efficient and reliable operation and maintenance support of the substations.
- 5.23.4.2** The SAS system shall have state-of-the art design, suitable for operation in a high voltage substation environment, follow the latest engineering practice; it shall ensure long-term compatibility requirements, continuity of equipment supply and the safety of the operating staff.
- 5.23.4.3** As shown in the SAS structure, protection is an integral part of the SAS, and protective relays shall be directly connected to the inter-bay bus in order to provide unrestricted access to all data and information stored in the relays and for changing protection parameters from the remote control location.
- 5.23.4.4** Failure behaviour of the hardware and software functions shall be addressed, and related diagnostic and rectification working instructions shall be provided. The system's performance in case of failure of communication to NLDC, main and redundant computer base workstations, central functions, data model, control and protection IEDs, station and bay level communication shall also be clearly addressed (shall be provided by the Manufacturer).
- 5.23.4.5** 400kV, 230 kV and 132 kV substations, can also be controlled from the control panel installed in the control room. The following modes of operation shall be possible:
- Emergency operation of breaker, disconnector, earthing switch etc. from the LCC.
 - Emergency operation of breaker, disconnector, earthing switch etc. from the backup mimic panel located in the new control room. Both, bay controller-guided and unguided operation shall be possible from this panel.
 - Normal operation of breaker, disconnector, earthing switch etc. from the station automation system's HMI located in the new control room.

5.23.5 Architecture & Components

- 5.23.5.1** The SAS design shall consider Rapid Spanning tree Protocol (RSTP) for 400kV, 230kV & 132kV level. For 400kV or Higher voltage level, Parallel Redundancy Protocol (PRP) shall be applicable in all aspects. However same protocol shall be used throughout the substation ,in that case protocol for the highest voltage level shall be prevailed.
- 5.23.5.2** Following components have to be provided in the SAS architecture:
- Server cum operating workstation- 02 Nos
 - Gateway computers with hardware based firewall including cyber security- 02 Nos
 - Engineering workstation- 01 Nos
 - Laser printer- 02 Nos
 - Programmable Ethernet switches- as required
 - GPS receiver- 01 Nos, 02 Nos (for PRP)
 - Monitors- as per scope of supply
 - Other accessories as shown in SAS architecture, scope of supply and as per system requirement

- 5.23.5.3** Operator workstations should have the teaming facility in the Ethernet LAN cards. Moreover, automatic stand by to hot conversion facility have to be available for both operator workstations. N-1 contingency criteria should be satisfied for all workstations, gateway computers, Ethernet switches and optical fiber links.
- 5.23.5.4** Common alarm unit shall be provided for notifying about important signals such as MCB status, device healthiness and tripping incidents of the feeders. The Unit should be capable of communicating with SAS.
- 5.23.5.5** NLDC provided Device ID should be used for the Identification of Switching Devices in the process display.
- 5.23.5.6** Audible alarm and buzzers must be provided with the SAS for important alarms and trip signals for the notification of the operators.
- 5.23.5.7** All devices of SAS workstations and gateway computers should be directly DC operated; alternatively AC operated devices supplied from substation DC sources through inverter may be provided with redundancy and sufficient capacity. Necessary inverter have to be supplied by the contractor is such case.
- 5.23.5.8** Energy meters need to be connected to SAS and energy values displayed in SAS have to be extracted from Energy meters.
- 5.23.5.9** Automatic Voltage Regulator (AVR) should be directly IEC 61850 protocols supported and connected to SAS. Complete tap changing facility with parallel operation should be available in SAS for the Transformers of the substation.
- 5.23.5.10** In case of Parallel Redundancy Protocol- Engineering workstation, AVR will be connected to both networks of the topology.
- 5.23.5.11** Separate GPS receivers have to be provided for individual ring of the PRP network.
- 5.23.5.12** Status of Ethernet Switches, GPS Controllers, and Gateways shall be monitored and available on Operators Work stations.
- 5.23.5.13** DC changeover scheme should be established for all components of the architecture.
- 5.23.5.14** Status of DFDR and IED healthiness should be available in SAS.
- 5.23.5.15** 33kV transformer incoming feeders of all substations should be operable from SAS.
- 5.23.5.16** A general arrangement of the Automation system shall include IEDs (Relay, BCU& meters), Ethernet switches, Server (Hot & Standby) with software, Operator Workstation, an Engineering PC, A 55" LED monitor, Printers, Hot & standby Gateway with redundant switch & hardware firewall, cables (Fiber optic, Ethernet, copper) & connector, panels etc.
- 5.23.5.17** The workstation & server PC shall be merged into one unit in general& it is preferable one. However, segregated design is also acceptable within the same price; No additional price shall be claimed due to such design. The Ethernet switches shall have at least 20% spare switches for future use. All components of SAS shall be IEC 61850 compliant. The SAS shall be located in the Main Control Room unless otherwise specified. Final design shall be subject to approval of Employer. The Engineering PC shall have minimum core i7, latest generation, clock speed of 3.4 GHz, 16GB RAM, 1 TB (RAID 1) SSD , 27" display, touch screen facility etc.

5.23.6 Modes of Operation

The operator stations and specified remote users shall have the following operational modes, each password protected.

- 5.23.6.1** Monitoring: Ability to select graphic displays and lists for display only. No capability to acknowledge alarms, complete controls or select items for inclusion in program functions.
- 5.23.6.2** Control: Selection of graphic display and lists. Able to acknowledge station and SAS alarms, complete controls, dressing etc. associated with normal real time of the control of the substation.
- 5.23.6.3** SAS Engineering: To provide all SAS monitoring functions, together with online facilities for program /database /format modifications and checking without the possibility of executing power system controls.
- 5.23.6.4** System Manager To provide access to all system functions, including assignment of passwords and system maintenance activities.
- 5.23.6.5** In addition, a facility to provide access to the numerical protection relays, change / modify relay settings & AVR parameters and fault recorder data shall be provided.
- 5.23.6.6** A series of passwords shall be personally assigned to operators in each of the above categories.
- 5.23.6.7** Substation operators shall have the possibility to log on to either substation workstation and to be allocated the appropriate mode of operation relevant to the password. SAS engineering work and access to the protection relay and disturbance reorder information shall generally be carried out at the engineering workstation or the remote master station.
- 5.23.6.8** All workstations and the system database shall function as a system. It shall not be necessary for example to acknowledge an alarm at more than one workstation.
- 5.23.6.9** Similarly, an operator's manual entry applied at one workstation shall be immediately displayed at other workstations where this data is presented.

5.23.7 Project Specifications-

Specific functions required and boundary conditions of the SAS are detailed elsewhere in this specification. The following project-specific drawings are attached:

- Overall single line diagram
- General system architecture
- Location of substation buildings
- Control and operation principles
- Protection schemes

5.23.8 Vendor's Experience and Local Support

Only experienced and technically capable Manufacturers with minimum 5 years' experience in design and supply of control and protection systems for electricity transmission and distribution applications will be accepted. Preferred Manufacturers will be those who have experience in deliveries of the full scope of station automation systems and services. This experience has to be substantiated by means of reference installations being in service under similar environmental conditions for at least 5 years. The vendor shall provide long-term, i.e. 10 years, guarantee of the complete SA system. In order to assess the Vendor's experience with similar projects, the Vendor is required to submit the following with his bid:

- Technical design specifications and description of SAS
- Catalogues and brochures of equipment and devices offered
- Reference list

The Vendor shall assure long-term maintenance and availability of spares. Moreover, a guarantee shall be submitted for the availability of spares during the lifetime of the SAS equipment (not less than 10 years).

5.23.9 Quality Assurance and Inspection

Quality assurance of design and development, production, installation and servicing of material and workmanship shall be governed by ISO 9001. Supporting documents to prove ISO 9001 third party approvals shall be provided with the offer.

The SAS shall be pre-assembled and tested at the Vendor's workshop before shipment.

5.23.10 General System Design

The system shall be so designed that personnel without any background in microprocessor-based technology can operate the system easily after having received some basic training.

System control from the substation control room will be done by means of an industrial computer (PC) operated by a mouse. The following HMI (Human Machine Interface) functions shall be provided:

- 1) Acquisition and plausibility check of switchgear status
- 2) Control of switchgear
- 3) Remote checking of device parameters and activation of alternative parameter sets in the connected protective relays
- 4) Display of actual measured values (U, I, P, Q, f)
- 5) Display of events
- 6) Display of alarms
- 7) Display of trends
- 8) Sequence control functions
- 9) Disturbance records and fault location
- 10) System self-supervision
- 11) Hard copy printing
- 12) Dynamic busbar colouring

5.23.11 The offered SAS shall support remote control and monitoring from the NLDC via an industrial grade gateway with redundant CPU as well as redundant DC/DC converters. PC-based gateways which contain moving parts will not be accepted. The gateway should be designed for a life of at least 20 years. The gateway shall provide for communication to/from remote control centres via the IEC 60870-5-101 protocol. Even if the station PC is not available, it shall be possible to control the station from the NLDC as well as from the backup control panel in the individual bays with all interlocks. Interlocking in case of emergency (i.e. if the bay controller fails) should be waived locally by means of a switch with key lock by the Maintenance Engineer for all the switchgear.

5.23.12 Maintenance, modification or extension of components shall not require a shutdown of the whole station automation system. Self-monitoring of single components, modules and communication shall be incorporated to increase the availability of the equipment while minimising maintenance time to repair.

5.23.13 As shown in the system drawing, the SAS shall be structured in two levels - station level and bay level. The data exchange between the electronic devices on

both levels shall take place via an inter-bay bus using IEC 61850 standards. The entire station shall be controlled and supervised from the station level PC. It shall also be possible to control, monitor and protect each individual bay from the respective bay level equipment for maintenance purposes or if the communication to a particular bay fails. Clear control priorities shall prevent initiation of operation of a single switch at the same time from more than one of the various control levels viz. NLDC, station level, bay level or switchgear (apparatus) level. The priority shall always be with the lowest enabled control level.

5.23.14 Bay control and protection units shall be independent of each other and their functioning shall not be affected by any fault occurring in any of the other bay control and protection units of the station.

5.23.15 The SAS shall contain the following main functional parts:

- 1) Human Machine Interface (HMI) with process database
- 2) Gateway function for remote control via an industrial grade hardware
- 3) Dial-in facility / laptop workstation for protection relay parameterization, disturbance analysis and SAS fault analysis.
- 4) Data exchange between the different system components via high speed bus
- 5) Bay level devices for control, monitoring and protection
- 6) Bay-oriented local control and protection panels with mimic inserts
- 7) Facility for emergency operation of all the switchgear, if the bay controller fails (key / master key system).

5.23.16 The main process information of the station shall be stored in distributed databases. The system shall be based on a decentralised concept with bay-oriented distributed intelligence for safety and availability reasons. Functions shall be decentralised, object-oriented and located as close as possible to the process.

5.23.17 The substation monitoring/protection system shall supply data for maintenance, repair and remote parameter setting of protection and control devices in the switchyard.

5.23.18 In the event of a fault in the electrical network, the substation monitoring shall provide a quick means for collecting the relevant and critical data of the fault.

5.23.19 The monitoring system shall be suitable for the supervision and monitoring of all the secondary (IED) and primary devices in a substation including future extensions.

5.23.20 Maintenance, modification or extension of components shall not cause a shut-off of the whole station monitoring system. Self-monitoring of single components, modules and communication shall be incorporated to increase the availability and the reliability of the equipment and to minimize maintenance.

5.23.21 It shall be possible to access all protection and control devices for reading the terminal parameters (settings). The setting of parameters or activation of parameter sets shall be restricted by password to the Protection Engineer.

5.23.22 One remote computer should be provided with access to the SMS and with different access levels. The required SMS software and application-specific firmware (for relay parameterization) shall be provided with associated tools and equipment. The required engineering tools and analyzing software shall also be provided/installed both in the station PC and the remote master analysis station. A backup copy of all the software shall be provided on CDs.

5.23.23 The SMS shall be capable of communicating with the remote master analysis station at the protection development branch through a modem over a dedicated or dial-up voice grade telephone line or microwave channel.

5.23.24 Flexibility and Scalability

The offered SAS concept shall be flexible and shall permit future extensions to be implemented easily. Preference will be given to those Suppliers who are in a position to provide protection and control devices that can be freely adapted to the required application functions.

5.23.25 System Hardware

5.23.25.1 Operator Station: The main operator station shall be based on an industrial PC hardware and high-resolution full-graphics screen with the Manufacturer's standard type-tested software operating under Windows NT environment. The Industrial processor shall be high end like Intel Xeon or similar. An event printer and a hard copy printer shall be connected via a printer server and LAN to the operator station.

5.23.25.2 Dual station computers shall control the SAS and drive the work stations and other peripherals. One of the station computers shall operate the system in the "online" state while the other acts as a "redundant hot standby". The standby computer shall be continuously updated and shall immediately take over the SAS duties without interruption or transfer mechanism should the online operator workstation fail.

5.23.25.3 Disturbance records shall be analysed using the installed disturbance record analysis programmes. The disturbance records will be collected, over the inter-bay bus, from the connected IEDs by the system software. All necessary facilities shall be provided to allow the system to perform spontaneous upload of disturbance data or their upload in a pre-programmed manner. The event printer shall print events spontaneously as they arrive in the main operator station.

5.23.25.4 Each uploaded data report file shall be reported on one line that shall contain:

- 1) The event date and time
- 2) The name of the event object
- 3) A descriptive text
- 4) The state or value of the object

5.23.25.5 The information fields above shall be structured in columns for maximum readability.

5.23.25.6 The hard copy printer shall permit printing of any picture (or part thereof) from the station level PCs using easily accessible commands from the window menus.

5.23.25.7 The main station PCs shall be supplied by the station DC battery and a UPS system with a supply duration of not less than 30 minutes to supply the monitor and the printers.

5.23.25.8 A 16-window annunciator unit shall be directly connected to the main station PCs to monitor the same and also to annunciate common station abnormal/fault conditions.

5.23.25.9 Station Inter-bay Bus: The LAN connecting the industrial computer-based operator workstations and printers shall be Ethernet 802.3 LAN, protocol TCP/IP (10 Mbit./ sec or higher), and the physical medium shall be thin Ethernet or fibre optic bus, provided this LAN is kept within the confines of the control room.

5.23.25.10 The bay control and protection units shall be connected via glass fibre optic cables to a station inter-bay bus using industrial grade Ethernet switches. The station bus according to IEC 61850-8 is today mapped to MSS / Ethernet (with priority tagging and with 100 MS/s). The standard is not making any provision on the Ethernet communication infrastructure. To at least ensure a certain level of quality, performance and availability, the Ethernet switches and topology shall fulfil at least the criteria described below.

- Industrial-grade Ethernet switches that fulfill the hardened requirements concerning temperature, EMC and power supply (110 V DC from the station battery) suitable to be installed in substations shall be provided, i.e. the same data as common for numerical protection.
- The use of Ethernet hubs is not permitted as they do not provide collision-free transmission.
- The switches shall support priority tagging and open standards for ring management like fast spanning tree to ensure that e.g. for later system extension the utility has not to rely on one switch supplier only.
- External switches shall be supplied as they have the advantage that there is no interruption or reconfiguration of the Ethernet ring, if one or several bay devices are taken out of service.
- To increase reliability, the Ethernet switches shall have redundant power supply & shall be powered from two different station batteries.

5.23.25.11 Protection and Control IEDs and Local Back-up Control Mimic on 400kV, 230 kV Level

The bay control IEDs, 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 measure for operation via the HMI. They shall perform all bay-related functions such as protection, commands, bay interlocking, data acquisition, data storage, event and disturbance recording, and shall provide inputs for status indication and outputs for commands. They shall be directly connected to the switchgear without any need for separate interposing equipment or transducers.

5.23.25.12 The numerical bay control IED shall be provided with a minimum of nine (9) configurable (current or voltage) analogue input channels and an adequate number of binary input & output channels which are galvanically isolated from the SAS. The channels shall also be individually separated from each other. HV switchgear and instrument transformers shall be directly connected to the bay level IED without any interposing equipment.

5.23.25.13 The devices shall meet the requirements for withstanding electromagnetic interference according to relevant parts of IEC 60255 to conform to the high requirements for operation on the secondary system of HV switchgear.

5.23.25.14 The 400kV, 230 kV and 132kV bay control & protection IED shall have the following minimum features:

- 1) a minimum of 9 configurable analogue channels
- 2) at least 32 binary inputs, 24 signal relays and 2 command relays
- 3) 16 LEDs on the front of the unit for indication

- 4) auto-reclose function
- 5) Synchrocheck function
- 6) power function which can be configured to measure forward or reverse, active or reactive power
- 7) four (4) independently settable parameter setting groups, settable/selectable locally or remotely via the HMI programme
- 8) 4 line local display units (LDU or front HMI) on the front of the relay which can display both input as well as measured quantities: frequency, phase currents, phase voltages, active power, reactive power, etc.
- 9) High-speed bus serial communication port as per IEC 61850 standards.
- 10) a sequence of events recorder with a buffer for 256 events and a resolution of 1 msec. The events to be recorded should be freely programmable. These could be alarm/trip signals, external signals connected to opto-coupler inputs, internal signals, etc. Once events are defined, they are recorded in chronological order as they occur.
- 11) Disturbance recorder function which can record 9 analogue values, 16 binary signals and 12 analogue channels for internal measurement values. It shall be possible to trigger the disturbance recorder function by any internal or external binary signal or internal protective function.
- 12) comprehensive self-supervision
- 13) battery-free memory back-up of event and disturbance records
- 14) logic functions (AND, OR, bistable flip flop, etc.)
- 15) delay/integrator function

5.23.25.15 The numerical bay control IEDs shall be mounted together with all the relevant bay protective relays in cubicles of protection class IP54 or better. Distributed back-up control mimics with associated switches meters and Indicating LEDs shall also be provided on these cubicles. These cubicles shall be installed in an air-conditioned room in the substation.

5.23.25.16 The distributed backup mimic for local control shall be installed next to the bay controller IED, which can be used in case of maintenance or emergency or if bay control IED fails. Local bay control via the back-up control mimic on the control & protection cubicles shall incorporate the same user safety measures e.g. bay interlocking, synchrocheck, interlock override user guidance etc. as the station HMI. Local bay control shall be key-locked, and the control either from remote control panel (in the new control room), the station HMI or from remote shall be disabled if the local/remote selector switch on the back-up control mimic is in the "local" position.

5.23.25.17 The electronic system has to be provided with functions for self-supervision and testing. Each circuit board shall contain circuits for automatic testing of its own function.

5.23.25.18 Faults in the bay control IED shall be indicated on a front HMI, and a message shall be sent to the station-level HMI. The time for fault tracing and replacement of a faulty unit shall be reduced to a minimum. The supervision shall also cover the power supply system, the internal system bus and the ability of the central processing module to communicate with different printed circuit boards.

5.23.25.19 Failure of any single component within the equipment shall neither cause unwanted operation nor lead to a complete system breakdown. The n-1 criterion must be maintained in worst case scenarios, also. Further, a single failure must not have any effect on the primary system, which is monitored and controlled.

5.23.25.20 Main protection shall be provided separately.

5.23.25.21 All IEDs shall have at least 5 years of successful proven experience in HV applications, and the MTBF for the offered units shall be provided.

5.23.26 Software Structure

5.23.26.1 The software package shall be structured according to the SAS architecture and shall be strictly divided into various levels. It shall be possible to extend the station with minimum possible effort. Maintenance, modification or extension of components of any feeder may not force a shutdown of the parts of the system which are not affected by the system adaptation.

5.23.26.2 Confirmation that the software programs will be supported for a minimum of 20 years is required to be submitted with the bid.

5.23.26.3 It shall be the responsibility of the Contractor to obtain any license required for the operation software. The Contractor shall indemnify the Client against all claims of infringement of any patent, registered design, copyright, trademark or trade name or other intellectual property right.

5.23.26.4

5.23.26.5 Station Level Software:

5.23.26.5.1 Human Machine Interface (HMI)

The base HMI software package for the operator station shall include the main SAS functions and 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. The system shall contain a library with standard functions and applications.

5.23.26.5.2 Operating System

A Windows NT workstation operating system shall be used for the operator station as it supports several standard system features, e.g. support for several Windows office applications, multitasking, security levels, data exchange mechanisms (DDE, OLE), open data base communication standards (ODBC) and a standardised, user-friendly look & feel HMI.

5.23.26.6 Bay Level Software

5.23.26.6.1 System Software

The system software shall be structured in various levels. This software shall be placed in a non-volatile memory. Its lowest level shall assure system performance and contain basic functions, which shall not be accessible by the Application and Maintenance Engineer for modification. The system shall support the generation of typical control macros and a process database for user-specific data storage.

5.23.26.6.2 Application Software

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

5.23.27 System Testing

The Supplier shall submit a test specification for factory acceptance test (FAT) and commissioning tests of the station automation system for approval. For the individual bay level IEDs, applicable type test certificates shall be submitted.

The manufacturing phase of the SAS shall be concluded by a FAT. The purpose is to ensure that the Contractor has interpreted the specified requirements correctly. 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 with site conditions simulated to the extent possible in a test lab. If the FAT involves only a certain portion of the system for practical reasons, it has to be assured that this test configuration contains at least one unit of each and every type of equipment incorporated in the delivered system.

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

5.23.28 System Functions

5.23.28.1 Control Unit Functions

5.23.28.1.1 Control

The different high voltage apparatuses in the station shall either be operated manually by the operator or automatically by programmed switching sequences.

The control function shall comprise:

- 1) Commands from different operator places, e.g. from the associated control centre (NLDC), station HMI, or the control panel (in control room) according to the operating principle
- 2) Select-before-execute commands
- 3) Operation from only one operator place at a time.
- 4) Operation depending on conditions from other functions, such as interlocking, synchro check, operator mode, or external status conditions.

The control function shall also include:

- 1) Prevention of double operation
- 2) Command supervision
- 3) Selection of operator place
- 4) Block/de-block of operation
- 5) Block/de-block of updating of position indications
- 6) Manual setting of position indications
- 7) Overriding of the interlocking function (Second key switch.)
- 8) Switchgear run time supervision

5.23.28.1.2 Status Supervision

The position of each switchgear, e.g. circuit breaker, isolator, earthing switch, etc., shall be permanently supervised. Every detected change of position shall be immediately visible on the screen in the single-line diagram, be recorded in the event list, and a hard copy printout shall be produced. Alarms shall be initiated in case spontaneous position changes took place.

Each position of an apparatus shall be indicated using two binary auxiliary normally closed (NC) and normally open (NO) contacts. An alarm shall be initiated if these position

indications are inconsistent or indicate an excessive running time of the operating mechanism to change position.

5.23.28.1.3 Interlocking

The interlocking function prevents unsafe operation of apparatuses such as isolators and earthing switches within a bay or station-wide. The operation of the switchgear shall only be possible when certain conditions are fulfilled. The interlocking function is required to be decentralised so that it does not depend on a central control device. Communication between the various bays for the station interlocking shall take place via bay communication system.

An override function shall be provided, which can be enabled to by-pass the interlocking function via a key/password, in cases of maintenance or emergency situations.

5.23.28.1.4 Measurement

Analogue inputs for voltage and current measurements shall be connected directly to the voltage transformers (VT) and the current transformers (CT) without intermediate transducers. The correlated values of active power (W), reactive power (VAr), frequency (Hz), and the rms values for voltage (U) and current (I) shall be calculated.

5.23.28.1.5 Event and Alarm Handling

Events and alarms shall be generated either by the switchgear, by the control devices or by the station level unit. They shall be recorded in an event list in the station HMI. Alarms shall be recorded in a separate alarm list and shall 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 time tagging shall be done at the lowest level where the event occurs, and the information shall be distributed with the time tagging.

5.23.28.1.6 Time Synchronisation

The time within the SAS shall be set via a GPS clock receiver connected directly to the bay level LAN. The time shall then be distributed to the control/protective devices via the high speed optic fibre bus. An accuracy of ± 1 ms within the station is required.

5.23.28.1.7 Synchronism and Energising Check

The synchronism and energizing check functions shall be distributed to the control and/or protective devices and shall have the following features:

- 1) Adjustable voltage, phase angle, and frequency difference.
- 2) Energizing for dead line - live bus, or live line - dead bus.
- 3) Settings for manual close command and auto-reclose command shall be adaptable to the operating times of the specific switchgear.

5.23.28.1.8 Voltage Selection

The voltages, which are relevant for the synchro check functions, depend 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, isolator, and earthing switch and shall be selected automatically by the control and protection IED.

5.23.28.2 HMI Functions

5.23.28.2.1 General

The operator station HMI shall provide basic functions for supervision and control of the substation. The operator shall give commands to the switchgear via the station monitor with the help of mouse clicks on soft-keys.

The HMI shall provide the operator with access to alarms and events displayed on the screen. Besides these lists on the screen, there shall be a print out of hard copies of alarms or events in an event log. The alarm list shall indicate persisting and fleeting alarms separately.

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

5.23.28.2.3 The following standard pictures shall be available from the HMI:

- 1) single-line diagram showing the switching status and measured values
- 2) control dialogues
- 3) measurement dialogues
- 4) blocking dialogues
- 5) alarm list, station / bay oriented
- 6) event list, station / bay oriented
- 7) system status
- 8) checking of parameter setting

5.23.28.2.4 HMI Design Principles

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

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

- 1) selected object under command
- 2) selected on the screen
- 3) not updated, obsolete value, not in use or not sampled
- 4) alarm or faulty state
- 5) warning or blocked
- 6) update blocked or manually updated
- 7) control blocked
- 8) normal state
- 9) busbar colouring to show live & dead bus.

5.23.28.2.5 Process Status Displays and Command Procedures: The process status of the substation in terms of actual values of currents, voltages, frequency, active and reactive power as well as the positions of circuit breakers, isolators and transformer tap changers are displayed in the station single-line diagram.

5.23.28.2.6 In order to ensure a high degree of security against unwanted operation, a special "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. After the "execution" of the command, the operated switch symbol shall blink until the switch has reached its final new position.

5.23.28.2.7 The system shall permit the operator to execute a command only if the selected object is not blocked and if no interlocking condition is going to be

violated The interlocking conditions shall be checked by the interlocking scheme which is implemented on bay level.

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

5.23.28.2.9 System Supervision Display

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

5.23.28.2.10 Reports

The SAS shall generate reports that provide time-related information on measured values and calculated values. The data displayed shall comprise:

Trend reports:

- 1) day (mean, peak)
- 2) month (mean, peak)
- 3) semi-annual (mean, peak)
- 4) year (mean, peak)

Historical reports:

- 1) day
- 2) week
- 3) month
- 4) year

5.23.28.2.11 There must be provision of automatically generated periodic reports (such as, 15mins/30mins/1hr etc) of all analog data (such as Current, Voltage, Real Power, Reactive Power, Power Factor, and Frequency).

5.23.28.2.12 It shall be possible to select the displayed values from the database online in the process display. 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 are kept in the memory.

5.23.28.2.13 This report shall be printed automatically at pre-selected times. It shall also be possible to print this report on request.

5.23.28.2.14 Trend Display (Historical Data): A trend is a time-related follow-up of process data. The analogue channels of all connected bay level devices ~~on the 132 kV level~~ shall be illustrated as trends. The trends shall be displayed in graphical form as columns or curve diagrams with 10 trends per screen as maximum.

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

5.23.28.3 Event List

5.23.28.3.1 The event list shall contain events, which are important for the control and monitoring of the substation. The time has to be displayed for each event.

5.23.28.3.2 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.

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

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

5.23.28.3.5 The chronological event list shall contain:

- 1) position changes of circuit breakers, isolators and earthing devices
- 2) indication of protective relay operations
- 3) fault signals from the switchgear
- 4) violation of upper and lower limits of analogue measured value
- 5) loss of communication

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

- 1) date and time
- 2) bay
- 3) device
- 4) function
- 5) alarm class

5.23.28.4 Alarm List

5.23.28.4.1 Faults and errors occurring in the substation shall be listed in an alarm list and shall be immediately transmitted to the control centre. The alarm list shall substitute a conventional alarm tableau and shall constitute an evaluation of all station alarms. It shall contain unacknowledged alarms and persisting faults. Date and time of occurrence shall be indicated.

5.23.28.4.2 The alarm list consists of a summary display of the present alarm situation. Each alarm shall be reported on one line that contains:

- 1) The alarm date and time
- 2) The name of the alarming object
- 3) A descriptive text
- 4) The acknowledgement state

5.23.28.4.3 The operator shall be able to acknowledge alarms, which shall be either audible or only displayed on the monitor. Acknowledged alarms shall be marked at the list.

5.23.28.4.4 Faults that appear and disappear without being acknowledged shall be specially presented in a separate list for fleeting alarms. For example due to bad contacts or intermittent operation.

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

5.23.28.5 Object Picture

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

- 1) type of blocking,
 - 2) authority
 - 3) local / remote control
 - 4) NLDC/SAS control
 - 5) errors,
 - 6) etc.,
- shall be displayed.

5.23.28.6 Control Dialogues

The operator shall give commands to the system by means of soft keys located on the single line diagram. It shall also be possible to use the keyboard for soft key activation. Data entry is performed with the keyboard.

5.23.28.7 User Authority Levels

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

- 1) Display only
- 2) Normal operation (e.g. open/close apparatus)
- 3) Restricted operation (e.g. by-passed interlock)
- 4) System administrator

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

- 1) No Engineering allowed
- 2) Engineering/configuration allowed
- 3) Entire system management allowed

5.23.28.7.3 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.

5.23.28.7.4 Controlling authority should be provided of NLDC control, Control from SAS HMI, Bay Controller, Mimic and Local Control Cubicle. Selected authority control must be displayed in the SAS monitor.

5.23.29 System Performance

The refresh/update times on the operator station PC under normal and calm conditions in the substation shall be according to the levels specified below:

Function	Typical values
Exchange of display (first reaction)	< 1 s
Presentation of a binary change in the process display	< 0.5 s
Presentation of an analogue change in the process display	< 1 s

From order to process output	< 0.5 s
From order to update of display	< 1.5 s

5.23.30 System Reliability

The SAS system shall be designed to satisfy very high demands for reliability and availability concerning:

- 1) Solid mechanical and electrical design
- 2) Security against electrical interference (EMI)
- 3) High quality components and boards
- 4) Modular, well-tested hardware
- 5) Thoroughly developed and tested modular software
- 6) Easy-to-understand programming language for application programming
- 7) Detailed graphical documentation, according to IEC 61131-3, of the application software
- 8) Built-in supervision and diagnostic functions
- 9) After sales service
- 10) Security
- 11) Experience of security requirements
- 12) Process know-how
- 13) Select before execute at operation
- 14) Process status representation as double indications
- 15) Distributed solution
- 16) Independent units connected to the local area network
- 17) Back-up functions
- 18) Panel design appropriate to the harsh electrical environment and ambient conditions
- 20) Panel grounding to provide immunity against transient ground potential rise

5.23.31 Configuration Tools

5.23.31.1 The configuration of the station HMI shall be made using the operator station working in Windows NT environment. The various functions shall be customised by easy to use interactive configuration tools. Configuration shall include the visual presentation of the object, adaptations needed in process database and adaptations of the communication configuration data.

5.23.31.2 A portable personal computer (PC) as a service unit shall be foreseen for on-site modifications of the control and protection devices. The service unit shall be used for documentation, test and commissioning.

5.23.31.3 The PC based service & support system shall be used for the following purposes:

- 1) System configuration
- 2) System testing
- 3) Help functions
- 4) Program documentation
- 5) Down- and up-loading of programs
- 6) System commissioning
- 7) Data base management
- 8) Changing peripheral parameters

5.23.31.4 The service & support system shall be able to monitor data in the running substation control system and to present changing variables on the display screen in graphic representation.

5.23.32 Documentation

The following documentation shall be provided for the system during the course of the project and they shall be consistent, CAD supported, and of similar look/feel:

- 1) List of drawings
- 2) Control room layout
- 3) Assembly drawing
- 4) Single line diagram
- 5) Block diagram
- 6) Circuit diagram
- 7) List of apparatus
- 8) List of labels
- 9) Functional design specification (FDS)
- 10) Test specification for factory acceptance test (FAT)
- 11) Logic diagram
- 12) List of signals
- 13) Operator's manual
- 14) Product manuals
- 15) Calculation for uninterrupted power supply (UPS) dimensioning
- 16) High-quality SCD file.

(Please refer to chapter 5.23.25.11 which specifies the requirements of the local back-up control mimic. This back-up control shall be used during emergency conditions, or bay control IED is out of service or when control from HMI workstation or from remote NCC has been lost.)

5.23.33 Indicating Meters in Local Back-up Control Panels

Each circuit shall be equipped with Indicating meter for measurement of three phase currents, voltages, frequency, power factor, active and reactive power. Repeat pulse outputs are to be provided from all energy meters, where specified.

5.23.34 Availability Calculations

The Contractor shall submit availability calculations for the offered substation automation system.

5.23.35 Testing and Commissioning

Testing and commissioning of the SAS must be performed by the engineer from manufacturer's side. The contractor may have to provide evidence of the manufacturer's authentication regarding the personnel and his experience in the relevant field.

5.24 Trip Circuit and Power Supply Supervision

- 5.24.1** Trip circuit supervision relays shall be provided to monitor each of the trip circuits of circuit breakers in the relay panel and each relay shall have sufficient contacts for visual/audible alarm and indication purposes.
- 5.24.2** The trip circuit supervision scheme shall provide continuous supervision of the trip circuits of the circuit breaker in either the open or closed position and independent of Local or Remote selection at the local operating position.
- 5.24.3** The trip circuit supervision scheme shall operate satisfactorily and correctly under such conditions.
- 5.24.4** Relay elements shall be delayed on drop-off to prevent false alarms during faults on dc wiring on adjacent circuits, or due to operation of a trip relay contact.
- 5.24.5** Series resistances shall be provided in trip circuit supervision circuits to prevent mal-tripping of a circuit breaker if a relay element is short circuited.
- 5.24.6** Relay alarm elements should be equipped with self-resetting flag indicators.
- 5.24.7** Where specified, time delayed power supply supervision relays shall be provided to monitor the duplicated d.c. power supplies for tripping, closing, CB fail, Busbar protection etc. within a relay panel. An alarm shall be given if either supply voltage falls below 70% of nominal voltage for a period in excess of 3 secs. The relay shall be equipped with a self-resetting flag indicator, and shall be suitable for continuous operation at 125% of nominal d.c. voltage. The relay used shall be of Europe/USA origin or other eligible countries with equivalent quality.

5.25 Busbar Voltage Selection

Where required, selected voltage references, one for each busbar, shall be employed for all indications, metering, protection and synchrocheck where appropriate. The correct voltage selection for the requirements of each circuit according to the busbar to which it is connected shall be obtained by internal selection in the BCU or Relay by directly connecting voltage transformers. External busbar VT selection through auxiliary relays will not be accepted.

5.26 Synchrocheck

- 5.26.1** Synchrocheck Scheme: Synchrocheck facilities are required at all circuit breakers controlling feeder circuits and bus coupler circuits, and LV circuit breakers controlling transformers.
- 5.26.2** The system provided under the Contract is to be to the approval of the Engineer and is to be such that the synchrocheck circuit must be established before the circuit breaker can be closed. Synchrocheck function will be performed by BCU (Bay Control Unit) for controlling from SAS or BCU. Synchrocheck function will be checked by Protective relays as shown in attached interlocking logics for controlling from Mimic.
- 5.26.3** Synchrocheck relays shall check the phase and magnitude and slip frequency of the voltage difference across the open circuit breaker with contacts connected to prevent inadvertent manual closing outside acceptable limits.
- 5.26.4** It shall be possible when closing via HMI Workstation or remote NCC to close a circuit breaker when both the line side and the busbar side of the circuit are dead by bypassing the synchrocheck relay. The dead line/dead busbar check shall be made

by means of 3 phase undervoltage devices. The primary circuit shall be deemed to be dead if the voltage of all three phases is less than 20% of nominal voltage.

5.26.5 It shall only be possible to operate on one circuit at a time.

5.27 Interlocking and Control Authority

5.27.1 Independent and identical interlocking/blocking conditions have to be established for Mimic and BCU control. Interlocks in Local Control Cubicle (LCC) will also be same in case of GIS.

5.27.2 For mimic control, interlocking/blocking conditions will be hardware based and established in CRP by taking the statuses of relevant devices to CRP. Contact multiplier relays can be used for the purpose. Wiring in the switchyard among the devices will not be accepted.

5.27.3 For controlling from BCU, interlock will be software based and established in BCU. Hardware based interlocks will never be bypassed in any mode of operation.

5.27.4 Interlock for maintenance mode will be established in LCC for GIS.

5.27.5 Interlock bypassing option should be available in Control Panel; should also be available in LCC in case of GIS.

5.27.6 More than one device will not be allowed for operation at the same time.

5.27.7 CB internal blocking such as Gas pressure lock-out, spring discharge etc will be applicable for all modes of operations.

5.27.8 Control Authority Switch shall be installed in Control Panel having 4 (four) independent positions: Off, Mimic, BCU and Remote. The switch can be in only one position at any given time.

5.27.9 Interlocking logics and control authorities must comply with the attached Interlocking Logic drawings.

5.28 Diagrams

The Contractor shall submit schematic diagrams for consideration of the Engineer within six months of the contract commencement date. Prior to preparation of schematic diagrams, the Contractor shall provide single line, block and logic diagrams in order to agree the circuit schemes and operating modes.

The Contractor will be provided with a set of drawings for Substations as soon as possible after award of Contract. As part of the contract documentation, the Contractor shall provide integrated sets of complete drawings (schematic and wiring diagrams and cable schedules etc.) for protection and substation automation

Protection SLD, Trip matrices and Interlocking logic block diagrams have to be integral part of schematic drawings of each Control and Protection panel.

5.29 Current Transformer Calculations

The Contractor shall submit to the Engineer detailed calculations substantiating the parameters of the current transformers he proposes to provide. They shall be presented within six weeks of the contract commencement date.

5.30 Energy Meter (Tariff Metering)

For each substation, the Contractor has to foresee one (or more) separate Metering cubicle(s). During the Design stage, the Contractor has to propose the final solution, which will be subject of the Employer's final approval

SL. No.	Description	Unit	PGCB's requirements	Bidder's data
1	Manufacturer's name		CEWE/Elster/Landis+Gyr/EDMI/SEL or equivalent	
2	Country of Origin		France/UK/USA/Switzerland/Sweden/Germany/EU or equivalent	
3	Model		Should be filled up by bidder	
4	Meter type		Numerical, programmable, multi-function, IEC 61850 complaint	
5	Display language		English	
6	Connection type		CT/VT operated, 3-phase, 4 wires, solidly grounded neutral	
7	Installation		Indoor installation	
8	Type of socket		To be mentioned	
9	Number of element	Nos	3 (three)	
10	Number of terminals	Nos	At least 10 (ten)	
11	Current range	A	1 to 10, user programmable	
12	Starting Current	A	0.1% of nominal	
13	Continuous Thermal current rating	A	1.5*In or higher	
14	Short time thermal rating	A	10*In or higher for 1sec	
15	Voltage range	V AC	50 to 82.5 (P-N) or higher range, Burden-10MΩ	
16	Overload voltage	V AC	1.3*Vn, continuous	
17	Burden			
	17.1 Current Circuit	VA/phase	< 0.1 @ 1A, < 0.5 @ 5A	
	17.2 Voltage Circuit (with auxiliary power)	VA/phase	< 0.1	
	17.3 Voltage Circuit (with self power)	VA/phase	< 6VA	
18	Auxiliary supply range		Dual Power Supply: i. 80V to 240V AC/DC or higher range ii. Self Power with VT voltage (80V to 130V AC)	
19	Operating frequency		50Hz (±5%)	
20	Measuring mode		True 4 quadrant	
21	Accuracy class		0.2 for kWh, 0.5 for kVARh	

SL. No.	Description	Unit	PGCB's requirements	Bidder's data
22	Losses at nominal load		To be mentioned	
23	Local communication		DLMS, RS232/RS485/Ethernet	
24	Remote communication		Standard metering protocol, MODBUS; Communication facility to Network Control Center should be available	
25	Software interfacing facility with PC		Should be available	
26	Software requirement		1. Should be able to configure and monitor with user friendly PC-based tool. 2. Necessary software for configuration and parameterization has to be supplied free of cost and without any time-bound license	
27	Password protection		Should be available for programming, configuration and read out meter data	
28	Meter sealing condition		Hermatically or Ultrasonic welded	
29	Display options		Built-in HMI LCD display, configurable display, including meter ID, power quadrant display	
30	Integration period		30 (thirty) minutes	
	Resetting period		1 (one) month	
	Cumulative MD transfer		Built-in	
	Cycle Timing device		Built-in	
31	Normal display list		• Complete LCD test, Present date, Present time • Current billing total kWh-Del, Current billing total kWh-Rec • Current billing total kVARh-(Q1+Q4), Current billing total kVARh-(Q2+Q3) • Current billing maximum kW-Del, Current billing maximum kW- Del Date, Current billing maximum kW-Del Time, Current billing cumulative kW-Del • Current billing maximum kW-Rec, Current billing maximum kW-Rec Date, Current billing maximum kW-Rec Time, Current billing cumulative kW-Rec • Phase A voltage, Phase B voltage, Phase C voltage	

SL. No.	Description	Unit	PGCB's requirements	Bidder's data
			- Phase A current, Phase B current, Phase C current - Phase A voltage angle, Phase B voltage angle, Phase C voltage angle - Phase A current angle, Phase B current angle, Phase C current angle - System PF-arithmetic, Line frequency	
32	Alternate mode display list		- Complete LCD test, Present date, Present time - Current billing total kWh-Del, Current billing total kWh-Rec - Current billing total kVARh-(Q1+Q4), Current billing total kVARh-(Q2+Q3) - System PF-arithmetic, Line frequency	
33	Online testing facility		Should be available with online CT shorting facility with security sealing provision	
34	Data storage		At least 32MB of nonvolatile memory for data storage and capable of simultaneously record 4 load profile recorders x 8 channels for at least 90days at 30 minute intervals.	
35	Data logging and event recording		Should be available	
36	In built clock		Should be available	
37	Provision of GPS synchronization		Should be available	
38	Additional Features (Optional)		i. Power Quality Measurement (At least 1 GB of memory, 192 channels of LDP, 24kHz waveform, 600 VSSI summary events, Wave View, Flicker, Power Harmonics and Interharmonics, Total Harmonic Distortion) ii. Necessary software for accessing the mentioned features should be provided without any time-bound license.	
39	Environment requirement			
	39.1 Ingress protection		IP54 or better	

SL. No.	Description	Unit	PGCB's requirements	Bidder's data
	39.2 Operating temperature		-10°C to +60°C	
	39.3 Storage temperature		-40°C to +80°C	
	39.4 Humidity range		0% to 95%, non-condensing	
40	Weight of the meter		To be mentioned	
41	Dimension of the meter		To be mentioned	
42	Outline, drawing and leaflets		To be provided	
43	Performance curves for balanced and unbalanced load		To be mentioned	
44	Year of manufacture		To be mentioned	
45	Minimum Battery Service life and shelf life	Years	10 (ten) & 15 (fifteen) respectively	
46	Meter service life	Years	15 (fifteen)	
47	Reference standard		Relevant ANSI/IEC standard	
48	Warranty	Years	3 (three)	
49	Type test certificate		Should be provided	