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Fluence Protection and Associated Monitoring Philosophy

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Overview

The Fluence general protection design includes three sections. The Medium Voltage Switchgear (MV) and the Low Voltage Switchboard (LV) sections will be included on most projects. The third section is the High Voltage Equipment (HV) that is included on projects where the connecting grid voltage is greater than 15kV and where the HV equipment will be owned and operated by Fluence.

The Fluence protective relay and meters of choice are the Schweitzer Engineering Laboratories, Inc. (SEL) products. This selection is based on features, cost, technical support, and the product warranty. In some cases an alternate manufacturer may be proposed, but the manufacturer must provide the same features and design flexibility, and must have similar support and warranties. Any differences must be clearly identified prior to Fluence review of an alternate manufacturer.

General Protection Requirements

1. Any 3-phase, phase-phase, and phase-ground fault must be detected by at least two relays unless the fault impedance lowers the fault current to less than 150% of maximum generation/charging/load for phase faults and less than 25% of current for a bolted ground fault (no fault impedance) while maintaining equipment voltage withstand ratings.
2. Primary relays (not necessarily the backups) should always protect equipment from additional thermal, electrical or mechanical failures.
3. In addition to detecting all phase and ground faults within the zone of protection (to the next breaker) and backing up the next zone of protection, phase pickup elements shall be set to comply with the latest approved NERC PRC-025 (or equivalent international standard) with consideration of any draft document. The project may not be required to comply with this standard, but this benchmark is the desired approach for future required compliance.
4. All primary and backup relays shall coordinate with adequate margin so the faulted equipment is clearly identified by the relay targets and only the relay(s) protecting the faulted equipment trip a breaker. For ungrounded systems an exception may be granted. See the Ungrounded Systems Considerations below.
5. All relay CTs shall provide adequate voltage support during a fault to facilitate proper relaying. All CTs shall limit secondary current to acceptable values for the secondary terminals and wiring and shall maintain appropriate metering accuracy across the range of the facility's capabilities.
6. All PTs shall be able to carry the connected burden including resistors for ferroresonance suppression and shall support the expected overvoltage conditions that occur during faults.
7. All relays that use programmable pushbuttons or LEDS shall have labels clearly identifying the function. Unused programmable pushbuttons or LEDS shall be labeled accordingly.

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8. All I/O assignments shall be consistent across all relays so the 52A and breaker alarms use the same inputs on all relays. If a relay uses different I/O boards, then the inputs and outputs should be used in the same order even though the specific I/O may not match the same name as the other relays.
9. Arc flash outputs that are intended to trip the breaker with the highest amount of current shall use the high speed output contacts and shall be wired directly to the breaker trip circuit.
10. Miscellaneous relay settings such as event recording and SER settings shall be programmed in a consistent manner between relays.
11. Local breaker controls will be via a control handle switch on the panel with the ability to open and close the breaker. The control switch or control switch mounted buttons will include a built-in time delay to delay breaker closing. The control switch can also delay breaker opening but the opening function without time delay shall be maintained via the control switch handle. See the general electrical specification.
12. All protective relays and meters shall be connected to a GPS time source.


Arc Flash Mitigation

1. The design of the system shall be to minimize the incident energy level. Engineering effort shall be put into keep the PPE level to no higher than Level 2; incident energy < 8 cal/cm², in areas where personnel routinely may be subjected to energized components.
2. The arc flash analysis shall provide proof of meeting the Level 2 requirement. Locations where there is no plausible reason for personnel access while energized shall not be held to this standard. These types of instances shall be handled by procedural mitigation.
3. As part of the arc flash study, provide appropriate labeling on electrical equipment, down to, and including MV switchgear, transformers, inverters, DC battery racks, and AC and DC auxiliary systems.
4. Arc Flash regulations to be followed:
 - a. IEEE 1584 Guide for Performing Arc-Flash Hazard Calculations.
 - b. NFPA 70E, Standard for Electrical Safety Requirements for Employee Workplaces
5. The arc flash protection system may include the use of SEL 751A relays; combining light-sensing technology with fast overcurrent protection in order to mitigate the arc flash.


MV Specific Protection Requirements

Main Breaker/Bus

1. Use an SEL 751A or equivalent protection relay to monitor the MV bus three-phase voltage and the three-phase CTs connected on the incoming line side of the Main breaker.
2. For impedance grounded systems, connect a lower ratio neutral CT, lower ratio window CT or a summation of the phase CT circuits into the 4th CT input on the relay. The relay may require to be specified with a sensitive 4th CT input. This should be verified before ordering the relays.

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3. For ungrounded systems see the Ungrounded Systems Considerations below.
4. Set the current supervision at 120% of maximum generation/charging/load which will typically be 1.2 x Total Inverters rating. Maximum generation/charging/load should be verified by Fluence for each project. Current supervision should also be set at 65% or less of the minimum phase fault current. Conflicts with the above criteria should be discussed with Fluence.
5. Include a combination of Instantaneous (50) and/or Inverse Time-Overcurrent (51) phase protection to detect all phase faults and provide the necessary coordination. Relaying should be set to trip as quickly as possible while still maintaining coordination with adequate margins to avoid overtripping.
6. Include a combination of Instantaneous (50) and/or Inverse Time-Overcurrent (51) ground protection to detect all ground faults and provide the necessary coordination. Relaying should be set to trip as quickly as possible while still maintaining coordination with adequate margins to avoid overtripping. In the case of ungrounded systems, see the Ungrounded Systems Considerations below.
7. Utilize a “Fast-bus Tripping” scheme in conjunction with indication from the feeder relays to provide relatively high speed tripping for bus faults. This scheme should use Definite-time overcurrent elements (phase and ground) that are time delayed by approximately 2 cycles or as determined by the engineer. This time delay is to allow the feeder relays to indicate via a contact output on the feeder connected to a common digital input on the main relay, that the feeder has seen the fault and the main relay should not trip.
8. All protective elements shall trip the Main breaker as well as an 86 lockout relay.
9. The Main breaker’s 86 lockout relay shall trip and block close the Main breaker and all breakers connected to the MV bus.
10. Communication settings will be coordinated with the SCADA system.
11. Unused default settings will be removed or turned off.
12. Relays with more than one set of settings (i.e. Group settings in SEL relays) will be programmed identically as well as forced to stay in Group 1.
13. Front panel display settings will be programmed to display any breaker alarms and shall automatically reset (non-latching) when the breaker alarms reset.
14. The breaker status shall be monitored via an input connected to a 52A auxiliary contact.
15. Breaker alarms include trip coil monitoring, spring charge, and TOC (truck operated cell) status to indicate racking position.
16. All breaker alarms shall include conditioning logic for transient assertions to prevent nuisance alarms. All conditioning logic shall be at the relay level. Logic conditioning is not allowed at the SCADA system level.
17. The SCADA breaker control shall be through the relay. SCADA breaker control shall only be allowed in the remote mode and shall be blocked in the local mode. A programmable pushbutton and associated LED shall be used for SCADA local vs remote selection. The LED shall be illuminated when the breaker is in remote and shall be extinguished when in local. The

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pushbutton shall toggle the status. The associated label shall clearly indicate the meaning of the LED.


18. The Lock pushbutton will not be used. The logic and labels should be removed.
19. Event recording shall be set to capture fault pickup and trips.
20. The sequential event recorder shall be set to capture fault pickup and trips, all digital inputs and outputs and intermediate elements appropriate for troubleshooting without selecting bits that will chatter.
21. Voltage sag/swell (if included in the relay) shall be set to capture 10% over or under voltages.
22. Battery monitoring will be set to capture high or low DC voltage. The high threshold shall be set above normal station battery charging voltage and the low threshold and conditioning timing shall be set to ride through station breaker operations that temporarily lower voltage and normal battery discharge prior to the charger turning on.

Feeder Breakers

1. Use an SEL 751A or equivalent to monitor the MV feeders to the LV transformers by connecting three-phase bus voltage and the three-phase CTs connected on the bus side of the feeder breaker if possible. Line side CTs may be used if required and FLUENCE approves.
2. Follow the same philosophy as the Main breaker with the following exceptions:
 - a. All protection elements will only trip the associated feeder breaker.
 - b. Backup protection shall detect faults on the LV bus when possible. Exceptions shall be documented.
 - c. FLUENCE may require tripping of the LV breakers associated with the feeder. This is to be verified with FLUENCE.
 - d. Instantaneous elements should be set higher than anticipated inrush current as seen by the specific relay.

Auxiliary Breakers


1. Use an SEL 751A or equivalent relay to monitor and protect the MV Auxiliary feeder for station load by connecting three-phase bus voltage and the three-phase CTs connected on the bus side of the auxiliary breaker if possible. Line side CTs may be used if required and FLUENCE approves.
2. Follow the same philosophy as the Main breaker with the following exceptions:
 - a. All protection elements will only trip the associated auxiliary breaker.
3. Alternatively, a fused disconnect switch may be proposed with Fluence approval to protect the feeder to the auxiliary transformer. The fuse shall be sized to carry the transformer inrush without blowing. The disconnect switch shall be motorized and shall have a time delay to allow for personnel locally operating the switch to step away from the equipment when the switch closes.

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HV Specific Protection Requirements (If a high voltage component of the project exists)

HV Breaker


1. Use an SEL 751A or equivalent protection relay to monitor the HV bus or line three-phase voltage if a PT exists and the breaker three-phase CTs connected on the line-side of the breaker (opposite the transformer).
2. A 4th ground CT input into the relay is connected to the transformer neutral CT. If the high side is a wye grounded connection, connect that CT, if the high side is a delta connection and the low side is a grounded wye connection, connect to the low side neutral CT. In some cases, the low side of the transformer may be delta connected, but a grounding bank may be connected between the transformer and the MV main breaker. In this case, connect the 4th CT input to the grounding bank CT. For impedance grounded systems, connect a lower ratio neutral CT into the 4th CT input on the relay from either the transformer or the grounding bank. The relay may require a specification using a sensitive 4th CT input. This should be verified before ordering the relay.
3. Include a combination of Instantaneous (50) and/or Inverse Time-Overcurrent (51) phase protection to detect all phase faults and provide the necessary coordination. Phase protection should also include overload protection. Relaying should be set to trip as quickly as possible while still maintaining coordination with adequate margins to avoid overtripping.
4. Include a combination of Instantaneous (50) and/or Inverse Time-Overcurrent (51) ground protection to detect all ground faults and provide the necessary coordination. Relaying should be set to trip as quickly as possible while still maintaining coordination with adequate margins to avoid overtripping. In the case of ungrounded systems, see the ungrounded systems dialog below.
5. If the relay is connected to a set of PTs on the HV side of the transformer, system overvoltage protection shall be applied. The tripping thresholds and time delays shall protect equipment from overvoltages while coordinating with any voltage tripping limitations from the interconnecting utility.
6. All protective elements shall trip the HV breaker as well as an 86 lockout relay.
7. The transformer 86 lockout relay shall trip and block close the HV breaker and the MV Main breaker.
8. Communication settings will be coordinated with the SCADA system.
9. Unused default settings will be removed or turned off.
10. Relays with more than one set of settings (i.e. Group settings in SEL relays) will be programmed identically as well as forced to stay in Group 1.
11. Front panel display settings will be programmed to display any breaker alarms that are needed. None are anticipated.
12. The breaker status shall be monitored via an input connected to a 52A auxiliary contact.
13. Breaker alarms include trip coil monitoring, spring charge, and SF6 gas pressure if applicable.

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14. All breaker alarms shall include logic for transient assertions that are normal conditions.
15. The SCADA breaker control shall be through the relay. SCADA breaker control shall only be allowed in the remote mode and shall be blocked in the local mode. A programmable pushbutton and associated LED shall be used for SCADA local vs remote selection. The LED shall be illuminated when the breaker is in remote and shall be extinguished when in local. The pushbutton shall toggle the status. The associated label shall clearly indicate the meaning of the LED.
16. The Lock pushbutton will not be used. The logic and labels should be removed.
17. Event recording will be set to capture fault pickup and trips.
18. The Sequential event recorder shall be set to capture fault pickup and trips, all digital inputs and outputs and intermediate elements appropriate for troubleshooting without selecting bits that will chatter.
19. Voltage sag/swell (if included in the relay) shall be set to capture 10% over or under voltages.
20. Battery monitoring will be set to capture high or low DC voltage. The high threshold shall be set above normal station battery charging voltage and the low threshold and timing shall be set to ride through station breaker operations that temporarily lower voltage and normal battery discharge prior to the charger turning on.

HV Transformer

1. Use an SEL-787 or equivalent to monitor three phase CTs on both the HV and LV side of the transformer. If possible, the CTs should be dedicated to the SEL-787, but if needed can share a CT with the SEL-751A. If possible the CTs should be on the HV breaker and the LV Main, opposite the transformer. If these CT locations are not available, alternate locations such as on the transformer or on the transformer side of the breaker may be acceptable. Recommend the alternative(s) to FLUENCE for approval.
2. Transformers with grounded wye windings on both the HV and LV terminals shall use the SEL-787 with the REF input. This input shall be connected to the transformer neutral CT on the LV terminal. The REF input of the relay shall be selected to minimize wiring complexity. The necessary sensitivity for the type of grounded system shall be determined prior to ordering the relay.
3. Include a combination of a restrained and unrestrained phase differential elements set per the manufacturer's recommendations for the transformer configuration and parameters. Harmonic restraint or blocking, DC Ratio blocking, or other manufacturer recommended methods shall be used to provide secure protection under all conditions.
4. Include a combination of Instantaneous (50) and/or Inverse Time-Overcurrent (51) phase protection on the HV winding to detect all phase faults and provide the necessary coordination. Relaying should be set to trip as quickly as possible while still maintaining coordination with adequate margins to avoid overtripping.

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5. Instantaneous elements should be set higher than anticipated inrush current as seen by the specific relay (approximately 6 times base rating) and no higher than 10 times base rating. If the desired setting falls outside these ranges, make a recommendation to FLUENCE for approval.
6. When the SEL-787 has the REF input wired to the neutral CT or a grounding bank (only applied when the HV and LV windings are grounded or include a ground bank), include a combination of Instantaneous (50) and/or Inverse Time-Overcurrent (51) ground protection to detect all ground faults and provide the necessary coordination. Relaying should be set to trip as quickly as possible while still maintaining coordination with adequate margins to avoid overtripping.
7. Use a sudden pressure (63), on line continuous monitoring system and SPR Seal-in package.
8. Use a thermal (49) device to monitor transformer heating.
9. Refer to the monitoring section for additional monitoring points.
10. Event recording will be set to capture fault pickup and trips.
11. The sequential event recorder shall be set to capture fault pickup and trips, all digital inputs and outputs and intermediate elements appropriate for troubleshooting without selecting bits that will chatter.

HV Interconnection


1. Specific projects may have additional interconnection protection requirements. These may include line relays, transfer tripping, synchronism checking, remedial action schemes, voltage tripping coordination, frequency tripping coordination, modification of existing protection, or other requests. Based on the utility provided interconnection requirements provide a recommended approach to FLUENCE for review.

Ungrounded Systems Considerations

Due to the inherent concerns of overvoltage and the need for more complicated protection schemes associated with ungrounded systems, impedance grounded systems are desired over ungrounded systems. However, FLUENCE projects will often be connected to existing ungrounded systems so this may be a required configuration.

Note that most utility and some industrial delta connected systems have generators connected to them that include impedance grounded neutrals. These systems provide a ground reference. However, these systems may not always be connected to the bus (which may be the primary reason for the FLUENCE project) or the bus system is truly an ungrounded bus. In these cases the project must design the system to address the overvoltage and different ground relaying techniques. Overvoltage including Ferro resonance may occur on ungrounded systems.

The FLUENCE philosophy is to standardize on the SEL-751A for all sites that are solidly grounded or impedance grounded where there is measureable current using the phase CTs. No separate window CTs for the neutral are needed in these cases. In the case where ground current is below the phase CT measurement capabilities, adding window CTs and changing the corresponding card in the SEL-751A

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should allow a more sensitive measurement that will be adequate for detection of ground faults. This will need to be verified. If the impedance ground point is on the incoming side of the Main breaker then directional elements are not needed.

The exception to using the 751A in one of these ways would be when the site is completely ungrounded or grounded through a very high impedance (referred to as ungrounded) such as a PT with resistors to control Ferro resonance. Industry research has identified the quickly increasing voltage that will damage equipment over time if ground faults occur for these systems. If this type of system is the only reasonable option, then the equipment specifications must be verified to withstand the overvoltage conditions.

The relaying for an ungrounded system will require zero sequence overvoltage detection at each Main and Feeder breaker. Thresholds shall be set to detect all ground faults in the switchgear but not remote utility ground faults. This type of protection, does not inherently time coordinate so time delays shall be provided for sequential tripping starting with the feeders followed by the main breaker. This will help with fault identification.

If there is concern over the speed of tripping relative to the overvoltage, then window CTs must be added, and the SEL-751 (no "A" designation) with the sensitive capacitive based directional element for ungrounded systems must be used. Prior to finalizing a relay scheme, the change to use the SEL-751 must be verified and discussed with FLUENCE. This scheme will be in addition to the zero-sequence overvoltage scheme described above.

General Monitoring Requirements


1. All alarms and analog values that are not included as part of the relays or meters shall be connected to an SEL-2411 to communicate with the Advancion network via Modbus/TCP. There shall be at least one SEL-2411 located in the switchgear for all switchgear alarms and one located in the HV relay rack for all HV transformer and additional breaker alarms if needed if a HV component of the project exists.
2. All metering shall be the SEL-735 unless specific utility requirements dictate differently.
3. Utility metering shall be determined by the interconnecting utility.
4. CT polarity shall be set according the following criteria: positive is for power flowing to the grid (generating) and negative is power flowing to the batteries (charging).

MV Specific Monitoring Requirements

Station Monitoring

1. Use an SEL-2411 to monitor all protective relay hardware alarm contacts.
2. Use the same SEL-2411 to monitor miscellaneous alarms if needed.

MV Breakers

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1. Use an SEL-735 for metering.
2. These meters may have specific SCADA table configurations. Obtain the requirements from FLUENCE.

LV Specific Monitoring Requirements

Transformer Monitoring

1. The project may include BESS transformer monitoring points such as pressure relief, temperatures, etc. In this case, the alarms or analog values shall be brought into the inverter .

HV Specific Monitoring Requirements (If a high voltage component of the project exists)

Transformer Monitoring

1. The project requires main transformer monitoring points such as pressure relief, winding and oil temperatures, fan control, LTC position if included, and other points as provided by the manufacturer. The alarms or analog values shall be brought into the HV SEL-2411 via direct measurement of the analog quantities or via alarm I/O points for both alarm and trip.
2. All electronic devices shall have their alarm contacts wired to the SEL-2411.


HV Breakers

1. Use an SEL-735 for metering.
2. These meters have specific SCADA table configurations. Obtain the requirements from FLUENCE.

Key Protection Tasks and Documentation

The following tasks shall be identified in the schedule and executed as part of the protection system efforts.

1. Relay specifications with full part numbers including any deviation from this philosophy document clearly identified for review.
2. Relay I/O assignments for review.
3. One-line, three-line, DC schematics for review. Including the main transformer (if part of the project), switchgear, and switchboard systems with respect to relaying and metering.
4. Utility interconnection protection compliance document identifying how each utility interconnection protection requirement is met by the proposed design for review.
5. Protection model for review that identifies the software used and the philosophy of how the model is constructed. Include the electronic file of the model in the software's format. A PSSE export may be requested or other software approved by FLUENCE.
6. Coordination/Arc flash study for review that identifies the coordination and arc flash philosophy. The documentation shall include: all protection elements used in the relays, a table of the


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resulting relay settings (pickup, curve, and time dial settings). Include voltage settings as needed.

7. Arc flash label design for review showing the arc flash label template.
8. Relay settings basis for review for the HV (if needed), MV, and LV documented. The basis document shall show all settings in the relay, identify if they are used or unused and what they are set to. The basis for the settings shall be referenced to another basis document or the basis shall be identified in the document by means of descriptive text or formulas. This will include but is not limited to, determination of all of the necessary settings in the relays for the specific model number and firmware ID:
 - a. Specific protection settings for the particular relay,
 - b. Logic for alarms,
 - c. Remote open and close logic
 - d. Protection timers,
 - e. Supervisory elements,
 - f. Miscellaneous protection settings (relay enable settings, CTR, PTR)
 - g. Output contact settings
 - h. Sequential event recorder settings
 - i. Event recorder settings
 - j. Load profile settings
 - k. Voltage Sag/Swell if available
 - l. Communication port settings
 - m. Communication Modbus map settings as needed
9. Relay logic diagrams for review showing all relay logic that is not embedded relay logic. All inputs and outputs shall be clearly defined. This includes pushbuttons, LEDs, outputs, inputs, virtual software bits, etc. SCADA points read by SCADA do not need to be documented if they are vendor defined points available without custom relay programming.
10. Meter settings for review clearly identifying any deviations from the standard FLUENCE approach.
11. Setting files for all above devices in manufacturer file format for downloading.
12. Field confirmation of the relay model numbers and firmware ID
13. Custom pushbutton and LED label files in manufacturer format ready for printing on manufacturer labels.

Key Post Engineering Protection Tasks and Documentation

1. Installing arc flash labels
2. Testing the primary equipment (CT saturation, contact resistance, instrument transformer ratio verification, etc.)
3. Installing the settings in the relays.
4. Installing custom pushbutton and LED labels
5. Writing the relay test procedures and issuing for review

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6. Testing the relay settings and logic are installed correctly and they meet the engineer's intent (highlight relay logic drawings as it is tested).
7. Testing the relay I/O
8. Testing the wiring meets the schematic functionally (highlight schematics as it is tested)
9. Scheme testing if any (cross tripping, breaker failure, etc. – schemes that involve multiple devices)
10. Arc flash timing test if arc flash with light detection is used.
11. Energization support
12. In-service load checks of all relays and meters
13. Relay GPS synchronization verification, initial setting of the correct date and time, clearing event records and SER records
14. Record as-built markups for any wiring changes or print changes to reflect the wiring
15. Record as-built settings
16. Compare as-built settings with engineered settings and validate all differences
17. Create a record package of all protection deliverables after incorporating any changes.

Inverter Energization Synchronization

If there is no plan to perform islanding mode, a synchronization check on the low voltage bus that connects the inverters to the grid is not needed. This is because the inverters will never be operated out of phase with the grid. The following operational cases apply to the inverters:

1. **Inverter Energization:** The inverters are configured to operate in grid-tie mode which means that they synchronize to the existing grid voltage as they come online. If the grid voltage is not already present at the inverter terminals when they are commanded on they will not synchronize successfully and will not come online.
2. **Grid De-energization:** The inverters are configured to use anti-islanding functionality to stop switching if they lose the grid. This prevents the inverters from islanding and losing synchronization to the grid if the grid is lost or disconnected.

A synchronization check would need to be considered if the inverters were to be configured and operated with islanding capability. This is because if the inverters were to operate disconnected from the grid, they could be out of synchronization, and a situation could potentially arise where the LV breaker could be closed