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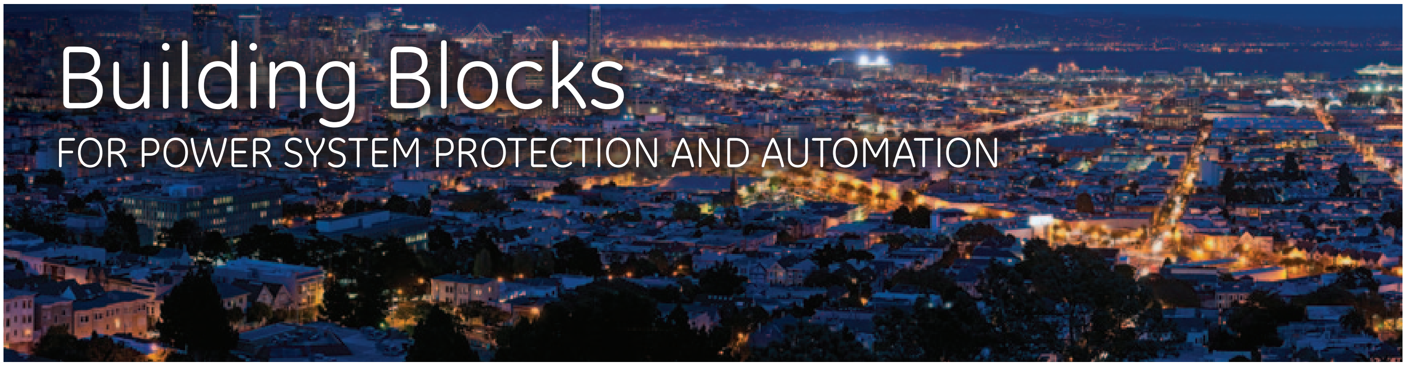

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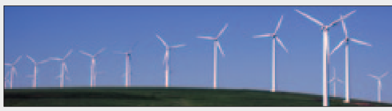

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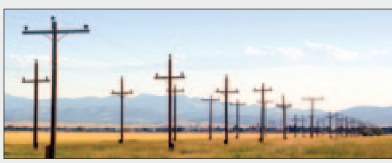

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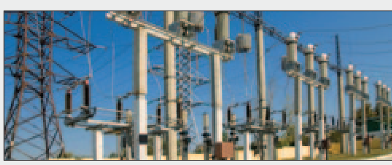

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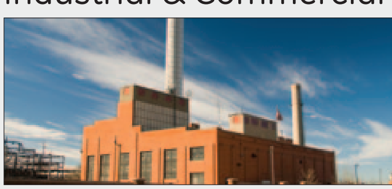

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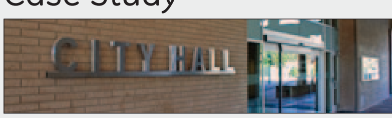
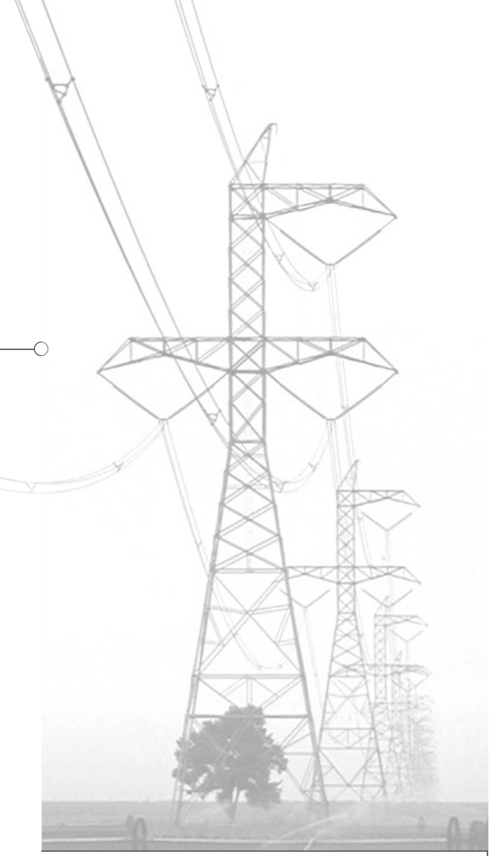


Bala Vinayagam
Marketing Director GE Digital Energy - Multilin



Building Blocks for the Modern Power Grid

The bridging of traditional power systems with a modern day high speed communication infrastructure has changed the way we protect, monitor and control the power grid and its assets.

Transmission utilities have implemented the Smart Grid for the past three decades by interconnecting substations to control centers and effectively controlling the way the power flowed in the high voltage grids. Due to the economic and environmental constraints of adding bulk power plants such as fossil or nuclear power plants, utilities have turned toward renewable power and its integration at the sub transmission and distribution level.

The bidirectional power flow at the distribution level has led to various challenges in terms of operating the grids at transmission or at distribution levels. The addition of electric vehicles, microgrids, home automation and smart appliances in the distribution network only compound operational challenges. Despite this, the fundamental nature of power systems remains the same, and operational challenges can be solved by making the grid smarter from generation to distribution to utilization of power.

Smart Grid deployments require data to flow seamlessly from various end devices such as meters, sensors, protection relays and automation devices to enterprise level control centers. This allows users to derive meaningful information to operate the power networks more efficiently, reliably and safely. Smart Grid applications and tools vary depending on the type of grid served, for example, transmission, sub transmission, distribution and industrial. The basic building blocks to feed these applications remain the same irrespective. The electrical assets have to be protected using modern IEDs (Intelligent Electronic Devices), interconnect these IEDs using a communication architecture through wired or wireless networks, allow a seamless flow of data to the outside world through a Gateway, and provide a local view of the network they are protecting.

The articles in this Journal explain the basic building blocks of such interconnected protection, control and automation systems across the power grid from generation and transmission to industrial and consumer distribution of power. Take for example, the paper "Application Considerations for System Integrity Protection Schemes (SIPS)". A SIPS scheme is nothing more than wide area protection of the transmission system, that uses the concepts of distance protection (described in "Distance Relay Fundamentals"), transmission line protection ("Transmission Line Protection Principles"), and the new tool of a phasor measurement unit (PMU) ("Application of a Phasor Measurement Unit for Disturbance Recording"). These application examples, along with other case studies and examples in this issue of the Journal, describe the building blocks of a protection and communication infrastructure that can be applied to increase the efficiency and reliability of power systems.

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To learn more about these and other solutions, visit the Digital Energy Solutions Explorer (gedigitalenergy.com/solutions). This interactive tool allows one to scroll across the power system by industry segment and view complete solutions, from Generation, Transmission and Distribution, to applications for Residential, Commercial, and Industrial users.

These application examples, along with other case studies and examples in this issue of the Journal, describe the building blocks of a protection and communication infrastructure that can be applied to increase the efficiency and reliability of power systems.

Dr. Bala Vinayagam has more than 14 years of experience in the field of Power System Protection, Control, and Automation. He has led efforts within GE to advance technology and was involved in defining and launching a range of smart grid products and solutions. He is also a member of IEEE and CIGRE and a member of IEC TC-57 WG on IEC61850. He has contributed more than 20 papers in various journals and conferences to advance the field.

Tieline Controls in Microgrid Applications

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1. Introduction

As electric distribution technology moves into the next century, many trends are becoming apparent that will change the requirements of energy delivery. These changes are being driven from both the demand side where higher energy availability and efficiency are desired, and from the supply side where the integration of distributed generation and peak-shaving technologies must be accommodated. Distribution systems possessing distributed generation and controllable loads with the ability to operate in both grid-connected and standalone modes are an important class of the so-called Microgrid power system (Figure 1).

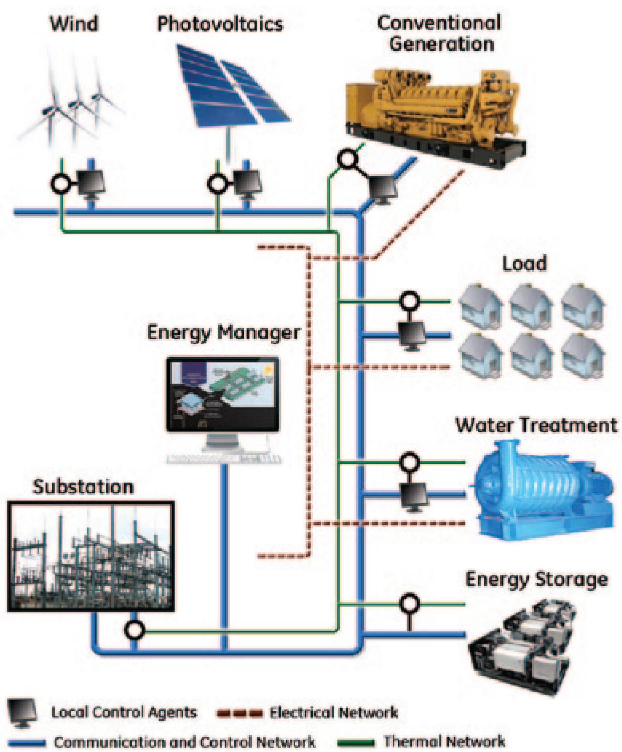

Figure 1.
Microgrid Power System

This class of Microgrid strives for optimized operation of the aggregated distribution system by coordinating the distributed generation and load resources - not only when connected to the main grid but also in a stand-alone mode. In either mode of operation, advanced local controls, energy management and protection technologies are required for robustness and reliability.

While the energy management optimization objective function can be tailored to the needs of each application, in general the overall objective is to optimize operating performance and cost in the normally grid-connected mode, while ensuring that the system is capable of meeting the performance requirements in stand-alone mode. One very appealing technology for grid connected operation is tieline controls, which will regulate the active and reactive power flow between the Microgrid and the bulk grid at the point of interconnection. These controls essentially allow the Microgrid to behave as an aggregated power entity that can be made dispatchable by the utility. Particularly beneficial to the utility is the fact that this feature can be designed to compensate for intermittency associated with renewable energy resources such as wind energy and solar energy, essentially pushing the management burden inside the Microgrid. This paper reviews the overall architecture of the Microgrid concept, and presents details associated with the tieline control features.

2. Microgrid Concept and Architecture

A report by Navigant Consulting [1] prepared for DOE's Office of Electricity Delivery and Energy Reliability identifies four classes of Microgrids:

Single Facility Microgrids

These Microgrids include installations such as industrial and commercial buildings, residential buildings, and hospitals, with loads typically under 2MW. These systems typically have low inertia and require backup generation for off-grid operation. Microgrids for these applications will be designed to have improved power availability and quality, and a subset of them, such as hospitals, will require a seamless transition between grid-connected and island operation.

Multiple Facility Microgrids

This category includes Microgrids spanning multiple buildings or structures, with loads typically ranging between 2 and 5MW. Examples include campuses (medical, academic, municipal, etc), military bases, industrial and commercial complexes, and building residential developments. As with single facility Microgrids, the design of multiple facility Microgrids will be driven by the need for high availability as well as improved power quality.

Feeder Microgrids

The feeder Microgrid will manage the generation and/or load of all entities within a distribution feeder – which can encompass 5-10MW. These Microgrids may incorporate smaller Microgrids – single or multiple facility – within them. The appeal of these Microgrids is the potential to realize regional improvements in availability, offered by the ability of the Microgrid to separate from the bulk grid during grid disturbances and service it's internal loads. Utilities, municipal utilities and coops are seen as future owners/operators of these Microgrids.

Substation Microgrids

The substation Microgrid will manage the generation and/or load of all entities connected to a distribution substation – which can encompass 5-10+MW. It will likely include some generation directly at the substation, as well as distributed generation and Microgrids included at the feeder and facility level. The appeal is again the potential to realize improvements in availability, offered by the ability of the Microgrid to separate from the bulk grid during disturbances and service its internal loads.

All of these Microgrid categories will benefit from the ability to control the dynamic exchange of power between the Microgrid and the bulk grid over the interconnecting tieline(s).

3. Tieline Control Design

A "tieline" refers to the feeder connection between the Microgrid and bulk grid. Tieline controls can be designed to manage the feeder power flow and voltage at the point of interconnection (POI) to meet the needs of the system operator. Control is implemented by coordinating the assets of the Microgrid, allowing the collection of these assets to appear as one aggregated dispatchable producing or consuming entity connected to the bulk grid. This section outlines the reactive and active power controls required for this capability.

Microgrid Reactive Power Control (M-VAR)

The primary functions of M-VAR are voltage regulation and power factor control at the tieline. Capabilities include voltage setpoint, steady state voltage response, and transient VAR response.

The M-VAR controller can receive either an external remote reactive power command or a voltage command from the system operator. The closed loop control issues reference VAR commands over the communication channel to each Microgrid controllable asset controller. The local controls [2] ultimately are responsible for regulating the VARs locally in each component. The controller compares the VAR output at the tieline or point of interconnection (POI) and adjusts the M-VAR command to obtain the desired system voltage. M-VAR control has two modes of operation: voltage regulated and VAR regulated (Figure 2). The voltage V_{poi} refers to the measured line-to-line RMS value. Q_{poi} is to the total reactive power measured at the POI.

In the voltage regulation mode, the voltage error is compensated by a proportional-integral (PI) controller to produce a total reactive power demand. After subtracting the shunt reactive power, provided by the shunt capacitors (if any), the total reactive power command, Q_{ttl},net, for the controllable asset in the Microgrid is obtained.

In the VAR regulation mode, the error between the Q reference and the Q measurement at the POI is regulated by a PI regulator. By adding the desired voltage feed forward, it provides a voltage reference to the voltage regulation loop. The total reactive power command is applied to the dispatch reference selection function to generate a reactive power command for each individual available controllable asset.

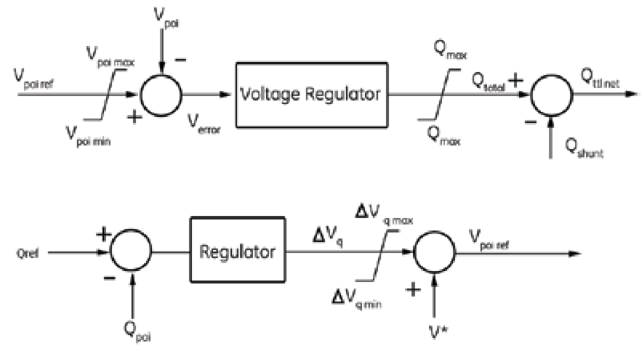

Figure 2.
M-VAR Block Diagram

Microgrid Active Power Control (M-APC)

The primary function of M-APC is to control steady-state and transient active power flow at the tieline. The objectives of the M-APC include:

- Enforcing power limits at the point of interconnection (POI)
- Enforcing ramp-rate limits at the POI
- Responding to system frequency excursions

These three functions are represented graphically in the block diagram in Figure 3. The parallel control loops for power limit, ramp rate limit and frequency limit will not be activated if all the operating conditions are within allowable limits. However, if any one of the controls is triggered, an adjustment command ***P is generated with the intent to bring the system back to the normal operating condition. A priority is given to each parallel control loop with power limit control having highest priority and ramp rate limit control having the lowest. The total adjustment command ***P is passed to the dispatch reference selection function, which allocates the ***P among the available controllable assets based on their participation factor assigned by the optimal dispatch control. The individual adjustment is added to the P set point from the optimal dispatch control to provide the final command to the controlled assets.

Power Limit Control.

Power limit control permits the system operator to assign a limit on the amount of active power that can be exported or imported from the grid. Power import and export are represented as negative and positive power, respectively, at the POI in the control.

Power Frequency Control.

Power frequency control is designed to support the grid frequency at the POI by adjusting active power. The inputs to the controller are the frequency and active power measured at the POI. The control law determines the power order in response to frequency excursions as specified by the system operator. A typical control law will require increased power output when frequency dips below nominal and decreased power output for increased frequency. The final output DP_{pr} is fed to the prioritization function.

Ramp Rate Limit Control.

It is anticipated that system operators will require ramp rate control of tieline power. This control will operate by adjusting the power output of Microgrid assets to compensate for the variable nature of Microgrid loads and generation. Two rate limits are specified for both increasing and decreasing power flow. The first applies to the maximum ramp rate averaged over one minute, and the second applies to the maximum ramp rate averaged over ten minutes. The ramp rate limit calculation is designed to meet these ramp rate limits, without unnecessarily penalizing.

Microgrid Energy Production.

Power is measured at the POI and passed through washout filters to determine the average ramp rates. The measured ramp rates are then compared with the ramp rate limits. The resulting error signals are compared and the most limiting is selected.

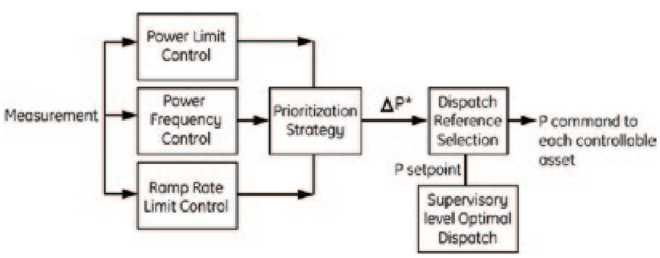

Figure 3.
M-APC Block Diagram

M-APC Regulator.

The error signals generated by power limit, ramp rate limit, and power frequency feed a prioritization block that selects a single error signal for control. This error signal is the input to a common M-APC regulator. The output of this regulator is a Microgrid power adjustment signal that is distributed to the controllable assets of the Microgrid.

4. Case Study Results on Tieline Controls

Case Study 1: Municipal Campus Microgrid

This case study examines a comprehensive and integrated solution to the challenge of providing reliable energy for a multi-facility Microgrid.

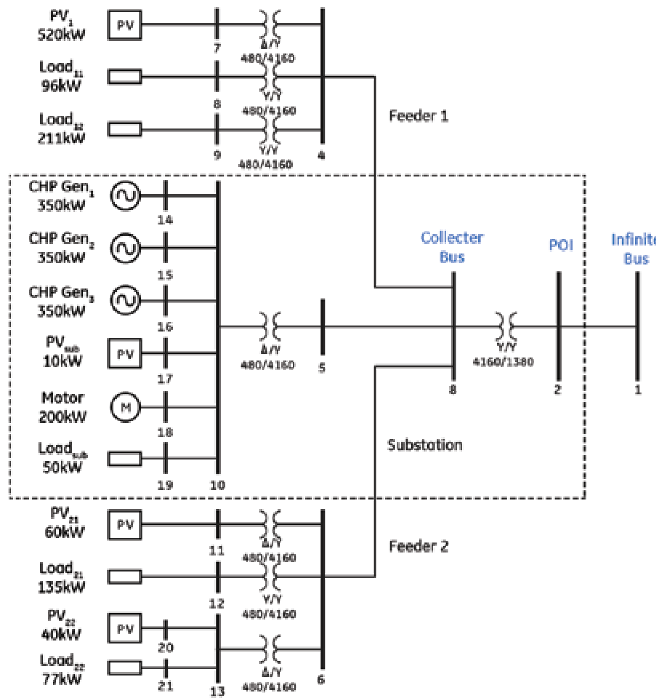

Figure 4.
Municipal Campus Microgrid

Figure 4 shows the municipal campus network considered in this example. Feeder one includes 100kW of critical loads and 200kW of noncritical loads and an aggregated solar PV system of 500kW. Feeder two includes two PV systems rated at 60kW and 40kW respectively, and two loads at 135kW and 80kW. The substation houses three 350kW engine gensets, a 10kW solar PV system, a 250KW operating load, and a 250kW motor load representing a chiller for CHP. The standard loads are modeled as P and Q controlled impedance loads, while the motor load is modeled as an induction motor. The solar PV system is modeled as a PV module with a DC/AC converter in d-q form. The PV array in the substation is modeled with VAR control capability. The power flow in the network is solved using a traditional load flow solution, which assumes balanced (positive sequence only) conditions. Since gensets 2 and 3 are a peaker unit and a backup unit respectively, in the test cases they are both offline. Only genset 1 and the small PV at the substation are considered controllable assets. The supervisory control includes the dispatch control as well as the tieline control (M-VAR and M-APC). The goal for this case study is to analyze the control performance for tieline controls.

Impact of Voltage Disturbance

The utility grid voltage is subject to variations that are usually within +/- 5% depending mainly on the voltage level, utility system operation and design practices. The simulation shown in Figure 5 illustrates some of the performance characteristics of the M-VAR control. M-VAR has two modes of operation: voltage regulated and VAR regulated. In this case, the system was operating under voltage control. That is, the MVAR modifies reactive power of controllable sources in order to maintain the POI voltage at its setpoint. The test consists of a 1% voltage step change at the "Infinite Bus" in Figure 4. Results are presented in Figure 5.

Shown in Figure 5 are the disturbance and variations at the POI. The transient voltage variation at the POI is relatively small. The reactive power variation at the POI is a result of the operation of the M-VAR. The active power at the POI varies due to the voltage variations inside the Microgrid. The reactive power commands to genset 1 and the PV at the substation are modified. The response time of the system is on the order of 15 seconds. This response is relatively slow compared to typical response times of excitation controls, avoiding undesirable interactions with other controls.

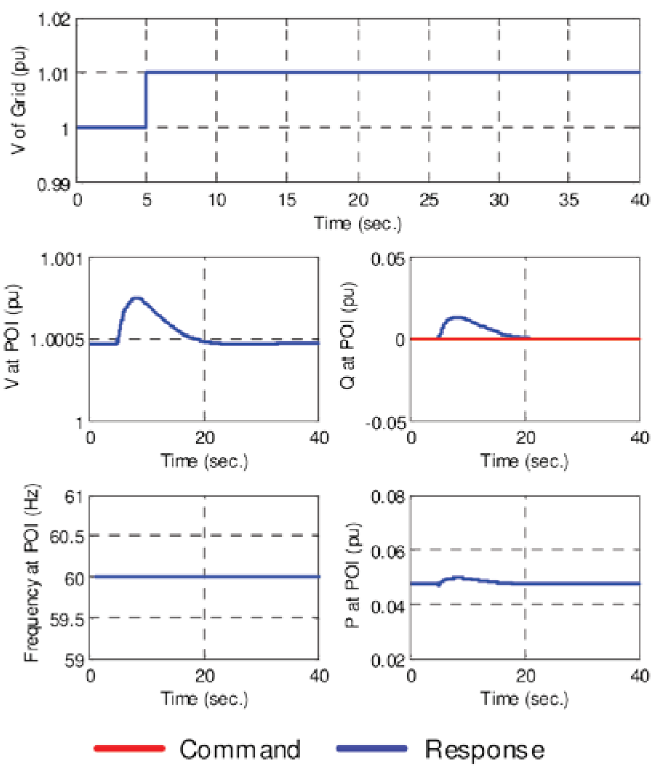

Figure 5.
Response at POI to +1% grid voltage change

Impact of Reactive Power Command Change

To maintain voltages throughout a distribution system, a utility may send reactive power commands from the control center. A Microgrid that can meet such commands supports the system operation and provides a potential market service opportunity. The simulation shown in Figure 6 illustrates the response of the M-VAR under reactive power control to an increase in reactive power command of 0.01pu (10MW base). Figure 6 presents the simulation results.

Shown in Figure 6 are magnitudes at the POI. The reactive power at the POI follows the command with a 15 second response time. The reactive power change causes an increase in the voltage at the POI and inside the Microgrid, while the impact on frequency is negligible. The test results show that the controls are able to respond to this command and supply the requested reactive power at the POI by allocating it amongst the controllable generation sources. In this case, the VAR dispatchable assets are engine genset 1 and the PV at the substation.

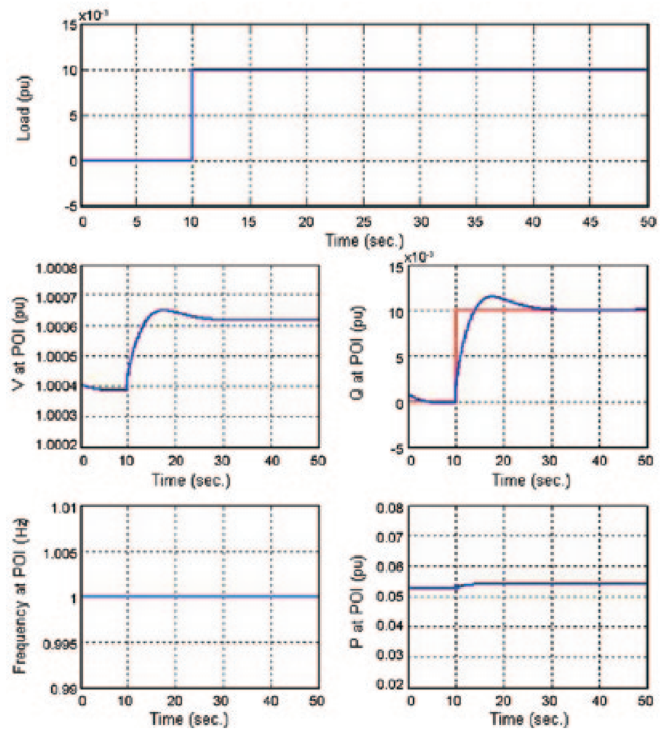

Figure 6.
Response at POI to +0.01 pu Q command change

Impact of Load Changes

The total load in the Microgrid is subject to demand changes. The system should adapt to load changes to not exceed operational limits at the POI, such as power export/import limits or power ramp rate limits. The examples in this section show M-APC control under 2 scenarios:

1. A load change that exceeds the power import limit, triggering the power limit control
2. A load change causing power at the POI to ramp at a rate that exceeds the ramp rate limit, triggering the power ramp rate limit control

Power Import/Export Limit.

In this example 750kW of load is ramped up in 4 seconds. The results are presented in Figure 7. This load change causes the power import to violate the import limit at the POI. The M-APC operates to increase the power from the controllable generators to bring the active power at the POI back within limits. Genset 1 is the controllable active power source in service. The governor response of Genset 1 is significantly faster than the M-APC and the power output and the command almost coincide. The M-APC control was not set to operate on active power rate limitation at the POI in this example. M-VAR is in reactive power control mode and operates to compensate for the reactive power changes at the POI. Due to the load change, the system moved to a new steady state with lower voltage at the POI while maintaining the commanded Q (0 pu).

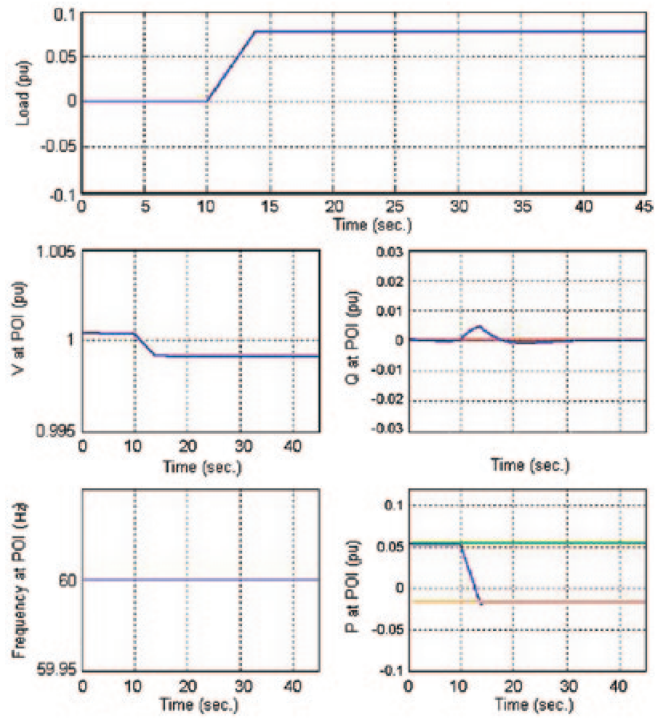

Figure 7.
Response at POI to load change (750kW) – Power Limit Control

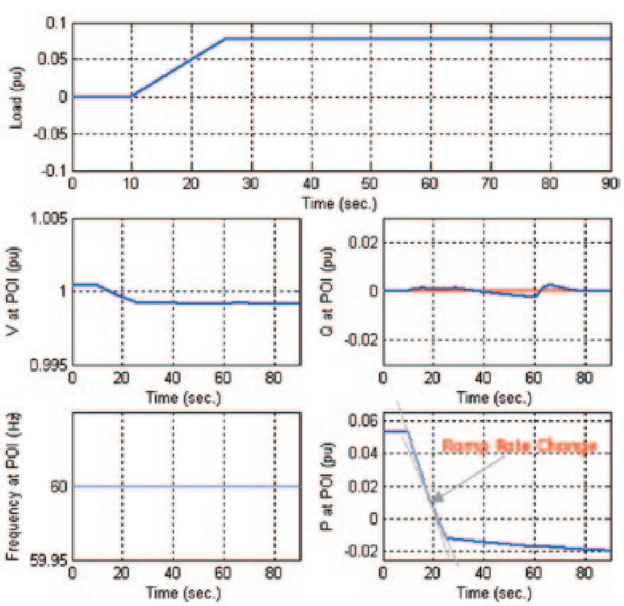

Figure 8.
Response at POI to Load change 50kW) – Power Ramp Rate Control

Ramp Rate Limit.

In this example (Figure 8), the M-APC is set to limit the ramp rate of active power at the POI. A 750 kW load is picked up in 15 seconds at the rate of 3MW/min, exceeding the 600kW/min limit at the POI. The M-APC control increases the active power output of the controllable generator to reduce the Microgrid active power rate of change. With this method of control, the Microgrid requires less active power support compared to a Microgrid without MAPC. Due to the load change, the system moved to a new steady state with lower voltage at the POI while maintaining the commanded Q (0 pu). The delta P command is dispatched to the only active power controllable generation, Genset 1.

Case Study 2: Island Microgrid

This second case study evaluates a potential Microgrid on an island (in the geographical sense). The model includes a 34.5KV line from a switching station to the Microgrid location. The network configuration is shown in Figure 9 as a single-line diagram. The model is tested with the tieline control concepts discussed in the previous section. The model includes:

- A model of a conventional run-of-river hydro generator of 500kW.
- A 15MW wind farm model represented by aggregating 10 x 1.5MW wind turbines.
- A conventional load modeled as a P & Q controlled impedance load.
- The tieline controls, which include M-VAR and M-APC controls.

To test extreme cases, load variation sizes and power import/export limits and ramp rate limits are assumed.

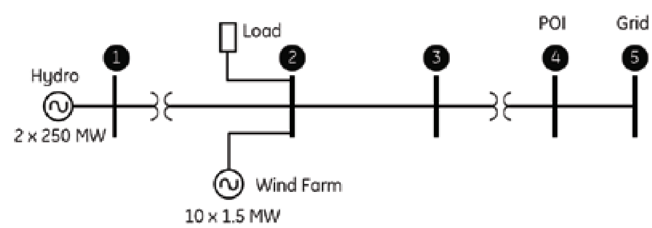

Figure 9.
Network Diagram for Case Study 2

Impact of Voltage Disturbance

A 1% voltage disturbance/step at the grid is applied at time t=30 seconds. This case is used to test the voltage regulation capability of the tieline control. Without a tieline controller, the voltage at the POI follows the disturbances and the effect of this disturbance is seen in the reactive and active powers at the POI as well as in all the wind and hydro assets (Figure 10).

M-VAR control will compensate for the voltage change at the grid side by dispatching VARs inside the Microgrid, so that the voltage at the POI will return to the setpoint after a short transient. The M-VAR control adjusts system reactive power to regulate voltage by commanding more VARs, allocating them among the wind and hydro. Figure 11 shows the results of a voltage disturbance at the grid, with M-VAR control and including wind variability. To show a clear response, a 2% grid voltage disturbance/step is applied in the variable wind case. Due to the variability of the wind, the control reaction in the test result is more difficult to discern, but it is clear that Q at the POI returns to its original average value. The test result shows that in the test time window, the ~30% power variation from wind causes about 0.5% of voltage fluctuation at the POI with the control.

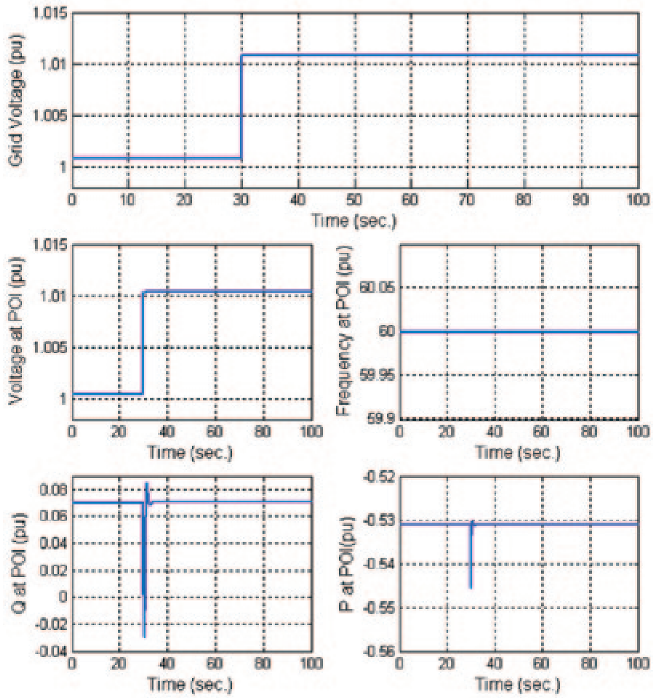

Figure 10.
Response to 1% grid voltage change – no Tieline Control, no wind variation

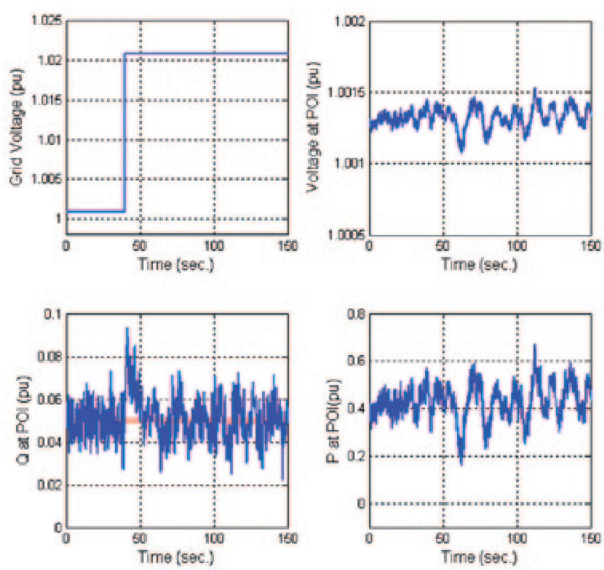

Figure 11.
Response to 2% grid voltage change with Tieline Control and wind variation

Impact of Reactive Power Command Change

Response to a reactive power commands would enable the Microgrid to provide VAR/Voltage regulation services. This test case is triggered by a Q command step change from an initial 500kVAR export to 0kVAR export at the POI. The test was performed under constant as well as time variable wind speed conditions. The results (Figure 12) show the system responds promptly and maintains voltage stability at the POI. The simulation results with wind variability (Figure 13) show clear reactive power response but no apparent voltage or active power changes.

Impact of Load Changes

Normally, the grid would cast a limit on how much power the Microgrid can import or export, as well as how fast the change can be. This capability ensures good grid citizenship. In this example, two scenarios are tested by a load change: active power import/export limit control and active power ramp rate control. In the first load change case (Figure 14), the load is ramped down from 10MW (1.0 pu) to 3.5MW (0.35 pu).

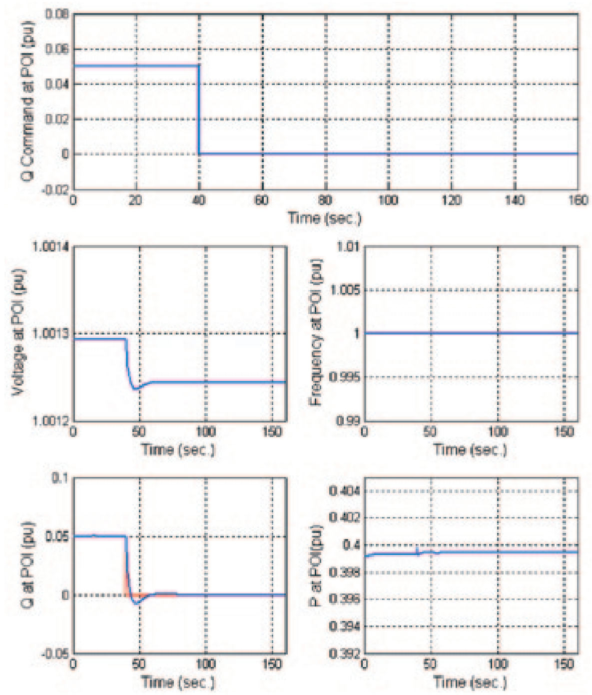

Figure 12.
Response to Q command change - no wind variability

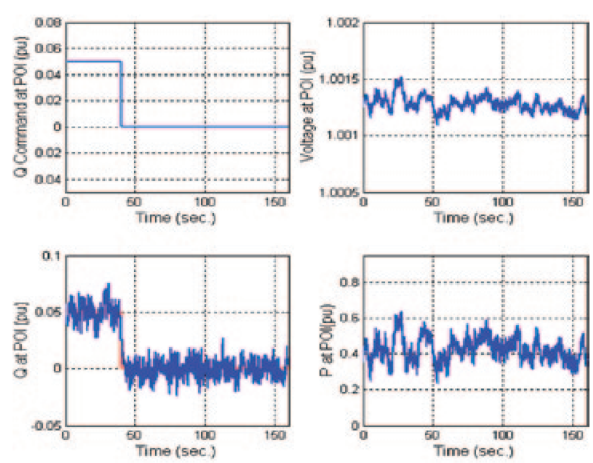

Figure 13.
Response to Q command change -wind variability

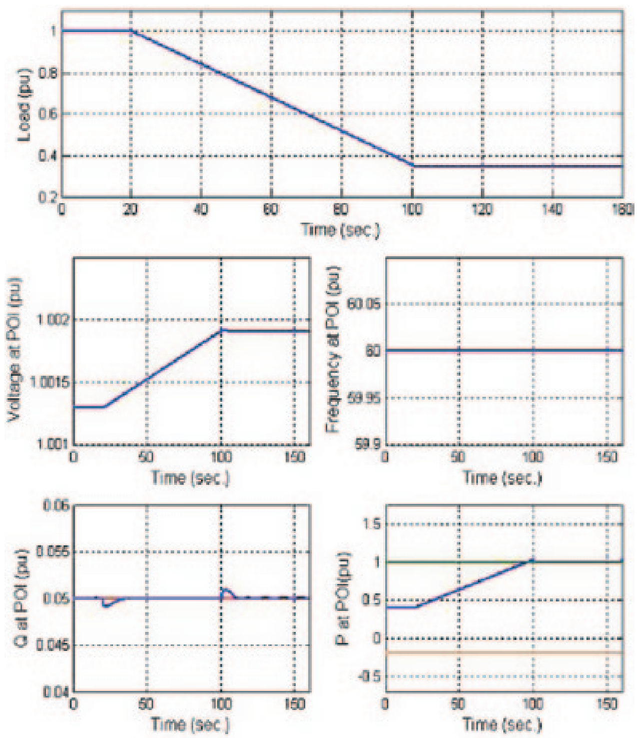

Figure 14.
Response to load change – Power Limit Control, no wind variation

The low load condition causes the power export to exceed a preset limit. As shown in the Figure, the violation triggers the M-APC, which controls the active power export so as not to exceed the limit by reducing the wind and hydro production.

Figure 15 shows the same test scenario with wind variation. The results show that meeting the power limit requirement with the fluctuation of the wind forces the hydro to be cycled more than 20%-30% of its capacity in a short time. This is not a desirable feature. An energy storage device may be able to take over some of the fluctuation and reduce the cycling of the hydro.

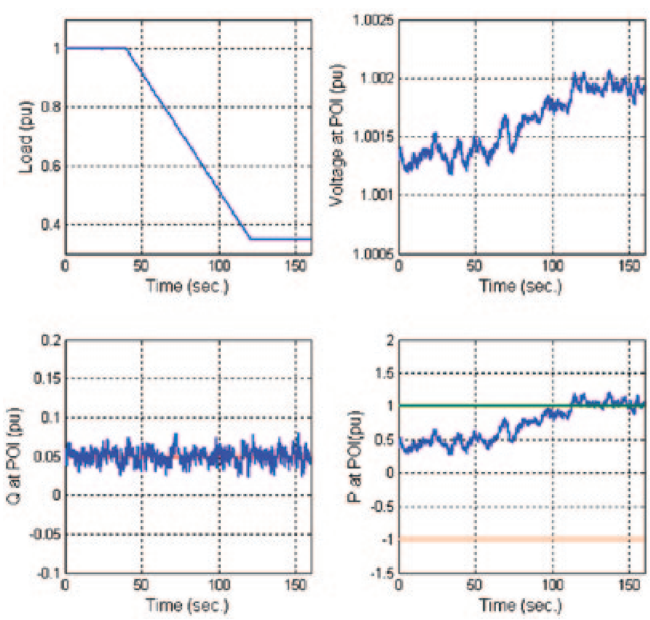

Figure 15.
Response to load change – Power Limit Control, wind variation

Another load change example has the load ramped down from an initial 19MW to 6MW at a rate of 0.2 MW/sec (Figure 16). A steady wind example is shown. This causes a violation of the active power 1-minute ramp rate limit (0.1 MW/sec).

As shown in Figure 16, the ramp rate of the active power at the POI is controlled to a slower rate of change when the ramp rate limit is exceeded. The ramp rate control of M-APC limits the ramp rate by adjusting the power from each generation source. The power reduction is dispatched among the wind and hydro assets.

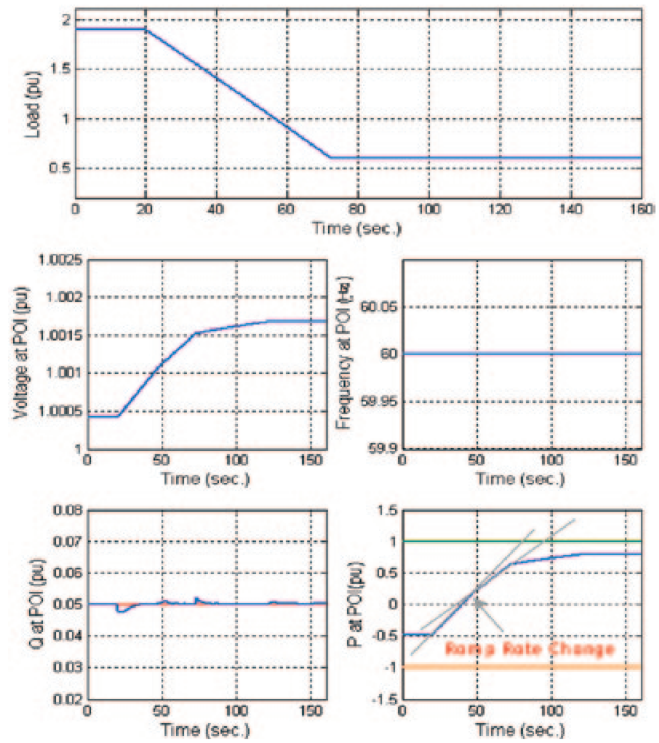

Figure 16.
Response to load change – Power Ramp Rate Control, no wind variation

5. Lab Demonstration

GE is working to identify a suitable centralized control hardware platform for Microgrid applications. Current lab testing employs a hardware-in-the-loop simulation of supervisory and tieline controls to validate their functionality. Figure 17 shows the layout for the laboratory setup. The setup includes four components:

- Single board computer (SBC) rack with QNX real-time operating system (RTOS), +/- 10V analog input and output cards.
- RT-LAB software coupled with generation and load asset models for the Microgrid.
- Supervisory controls developed using Simulink and linked with an OLE for Process Control (OPC) interface.
- GE Universal Relay (UR). The GE UR family [3] is a new generation of modular relays built on a common platform. The UR features high performance protection and communications.

RT-LAB software is used in conjunction with Simulink's Real-Time Workshop to compile the generation and load asset models into C code that can then be downloaded to the single board computer rack. These models consists of two generators and five loads that can be connected or disconnected to the system and a bus network that is connected to the grid. This model also includes drivers to interface with the digital-to-analog (D/A) and analog-to-digital (A/D) cards connected to the rack. The A/D card receives the active and reactive power commands for each generator from the UR as a voltage that is then scaled to the appropriate per unit value via a gain multiplier. The D/A card sends the scaled power and reactive power output of each generator, the reactive and active power at POI and the POI voltage and frequency to the UR.

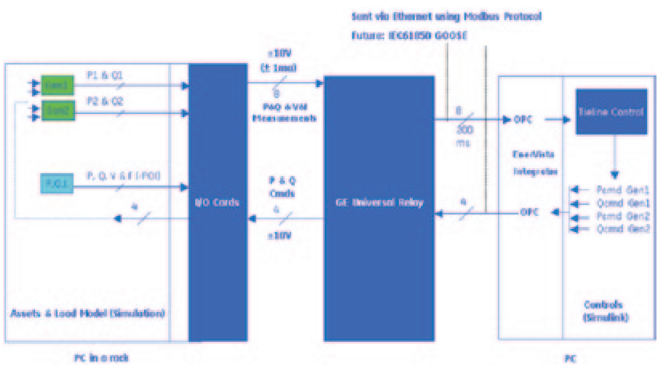

Figure 17.
Lab Setup Block Diagram

The UR is the hardware interface between the supervisory controls and generators. The analog measurements from the generators and POI are sent via Ethernet and IEC 61850 GOOSE/ OPC to the supervisory controls in Simulink. The supervisory controls recalculate the active and reactive power commands for each generator based on the current state of the generators and the POI. The new commands are then sent to the UR where they are scaled to a voltage that represents the analog value of the commands. The voltage is sensed by the SBC rack's analog input card and the generators adjust their output accordingly.

Lab Testing Results

The lab test shown in this section utilizes the electrical model developed for the Municipal Campus Microgrid described earlier and represented by Figure 4. This test case examines the system response after disconnecting a load from the Microgrid. The maximum connected Microgrid load is equal to 770 kW. The goal of the test is to confirm the functionality of the supervisory controls after the controls and generators have been separated into separate subsystems that interface with analog and OPC signals. In the test, a 0.03pu load is disconnected from the Microgrid. The results of the test are shown in Figure 18.

The generator responds to the active power command and behaves as expected. The M-APC increases the power from the controllable generator (Gen1) to keep the active power at the POI within the defined limit. The power flow at the POI indicates that power is now exported to the grid after the load is disconnected.

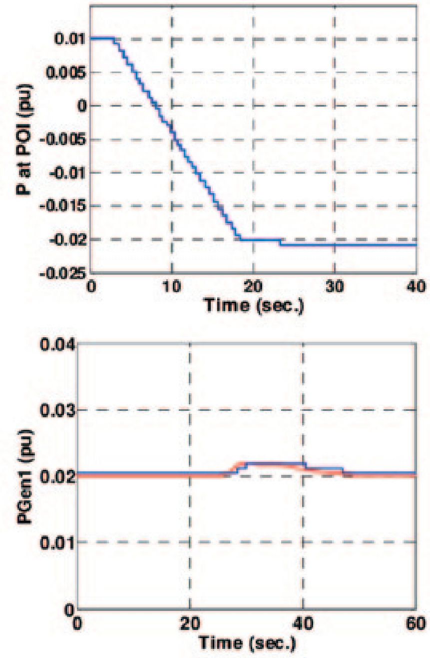

Figure 18.
Response to 30 kW load step change

6. Conclusions

This paper presents details on an important Microgrid control feature: tieline controls. These controls essentially coordinate the response of the several distributed energy resources within the Microgrid, such as generation, energy storage, or controllable loads, to make the response of the aggregate system at the point of interconnection to the grid resemble one single dispatchable entity. As such, the Microgrid can become a better citizen to the grid, managing its power exchange with the grid, and supporting voltage at the point of interconnection. One interesting benefit of this technology is that it can be designed to compensate for intermittency associated with renewable energy resources such as wind energy and solar energy, pushing the intermittency management burden inside the Microgrid, thereby potentially allowing for an increased penetration of these renewable energy resources. The dynamic response of the tieline control active and reactive power compensation elements were illustrated in several simulations, as well as in a hardware-in-the-loop simulation environment.

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Windfarm System Protection Using Peer-to-Peer Communications

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GE Energy

John Garrity
GE Corporate

1. Introduction

Windfarm electrical systems present some unique challenges for protection. The grid tie and wind turbine generators provide multiple sources of fault currents to be considered. Collector feeders become isolated ungrounded systems during faults due to separation from the centralized collector bus reference ground. Ground faults on feeders will result in unfaulted phase voltages rising to line levels. In addition, severe transient overvoltages can be produced, which can degrade insulation resulting in eventual equipment failure.

This paper reviews the overall requirements for comprehensive windfarm protection. It also focuses on the particular problem of feeder ground faults. A novel, yet simple solution is presented that makes use of peer-to-peer (GOOSE) messaging via the IEC61850 protocol. The characteristics of the GOOSE message are discussed with respect to speed and reliability and communications architecture is presented. The performance of the resulting protection scheme is quantified.

2. Wind-Turbine Protection Considerations

The type of wind turbine unit will have some bearing on the protection requirements. There are several Wind Turbine Generator (WTG) configurations in commercial operation today. This discussion focuses on the doubly fed induction generator (DFIG). Figure 1 shows a single line diagram of a typical WTG and the location of the IED.

In this configuration a variable-pitch wind turbine is connected through a gearbox to a wound rotor induction machine. Back-to-back voltage-sourced converters are used to connect the rotor circuit to the machine terminals in order to provide variable have grounded-wye connections. One LV winding is connected to the stator circuit, the other to the rotor circuit. The high voltage winding of the transformer may be connected to the grid through a circuit breaker or through fuses.

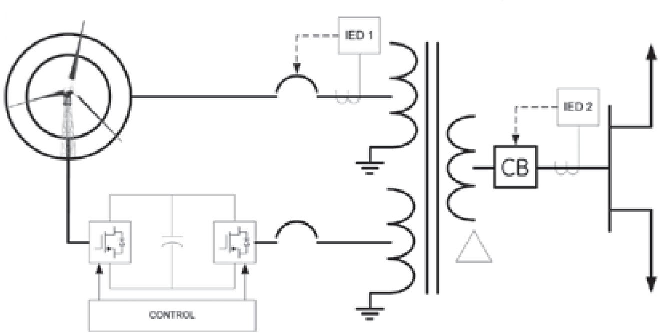

Figure 1.
WRG Single Line

Stator ground faults on the LV side of the WTG transformer are not detectable by upstream protections due to the transformer connection. The IED provides protection for these faults using an instantaneous overcurrent element. This element may respond to zero sequence, residual current, or transformer neutral current. The element requires no coordination with other protection elements, allowing it to operate with minimal time delay. If the element is measuring zero sequence via the phase currents or the residual current connection, then possible CT saturation during external faults should be considered when determining the pickup setting.

The IED also provides protection for LV phase faults. An instantaneous element will interrupt severe faults with minimal delay. Note that the DFIG will provide a contribution to external faults. This element should be set lower than the minimum current expected for a phase fault at the generator terminals and above the maximum expected generator contribution to a fault on the network. A time overcurrent element will detect phase faults internal to the generator. Upstream time overcurrent protections should coordinate with this element.

An IED with similar protection elements can also be applied to the converter circuit. This IED can detect faults up to the converter terminals but cannot detect faults in the rotor winding.

Auxiliary protective functions are also required for the DFIG. These protections may be embedded into the WTG controller or alternatively may be implemented within the IED. These include:

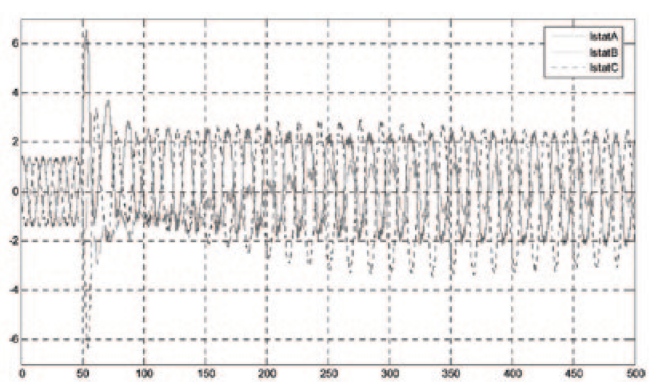

Figure 2.
Simulation of WTG Contribution (pu) to an External Ground Fault

- Voltage unbalance
- Overheating (RTDs)
- Reverse phasing
- Poor synchronizing
- Voltage and frequency out of limits

The WTG also must be capable of isolating itself from a fault on the feeder. Ideally, this should be done with minimal delay. At the same time external fault protection should never operate for faults on adjacent feeders or on adjacent WTGs. Practically, it is not possible to achieve this level of performance solely through measurement of local currents and voltages. Typically, grid fault detection relies on undervoltage and overvoltage elements. These elements are delayed to allow upstream protection to open the feeder breaker, thereby preventing a trip for fault on another feeder.

Finally, the WTG IED should have the abilities to capture voltage and current waveforms and sequence-of-events data during a fault or disturbance. These are valuable tools for fault analysis and verification of protection system performance.

3. Windfarm Substation Protection Considerations

Figure 2 shows the single-line diagram of a typical wind farm. Several feeders terminate at the collector bus. A power transformer steps up the voltage to the transmission level. A single HV transmission line connects the windfarm to the grid.

Protection is required for the collector bus. A high or low impedance differential element will produce the fastest clearing times for bus faults. If a low impedance bus differential scheme is used, then the feeder CT should not be paralleled. Otherwise the WTG fault contribution can produce a false operation if CT saturation occurs during an external fault.

A blocking scheme can be applied as an alternative to the bus differential. An overcurrent element in each of the feeder IEDs sends a blocking signal to an overcurrent element located in an IED on the transformer breaker on the occurrence of a downstream fault. When a bus fault occurs, no blocking signals are sent. GOOSE messaging, discussed in detail below, over the substation LAN provides a convenient method of exchanging the blocking signals.

Protection is also required for the power transformer. This will take the form of a percent differential element with inrush inhibit. If the number of feeders is low then the bus and transformer zones may be combined using a multi-restraint transformer differential element. This allows the transformer breaker and CTs to be eliminated.

The windfarm may be interconnected to the grid via a two terminal transmission line or it may be tapped onto a multi-terminal line. In either case the protection of the transmission line typically takes the form of line differential or distance elements. Each scheme will require a dedicated communication channel linking the windfarm to the remote utility terminal(s) to provide optimum protection. A communications channel can also be used to signal to the utility terminal that the windfarm has been disconnected and that reclosure is permissible. Out-of-phase reclosing onto the windfarm will produce severe torque transients and must be avoided.

Reclosing for ground faults can be implemented in the case that single-pole tripping is employed. In this scheme the windfarm remains synchronized with the grid through the healthy phases. This will increase the availability of the windfarm but requires protective IEDs and circuit breakers that are capable of single-pole operation.

4. Windfarm Feeder Topologies

There are several types of feeder topologies currently applied in windfarms. Radial, bifurcated radial, feeder-subfeeder, and looped topologies are the most common types used, each yielding their own distinct advantages and disadvantages. These factors and other criteria such as wind profiles, available tower placement, costs, etc. must be considered in order when determining which topology to use.

Radial collector system topologies are comprised of a single feeder circuit originating from the collector bus and connecting sequentially to each WTG tower. It provides the least complex feeder configuration and is best suited in applications where linear WTG placements are well defined. It has a lower installed cost per feeder due to the low complexity. Inter-tower cable faults or WTG faults can be isolated to allow continued production. However, a station circuit breaker failure or a cable fault between the station

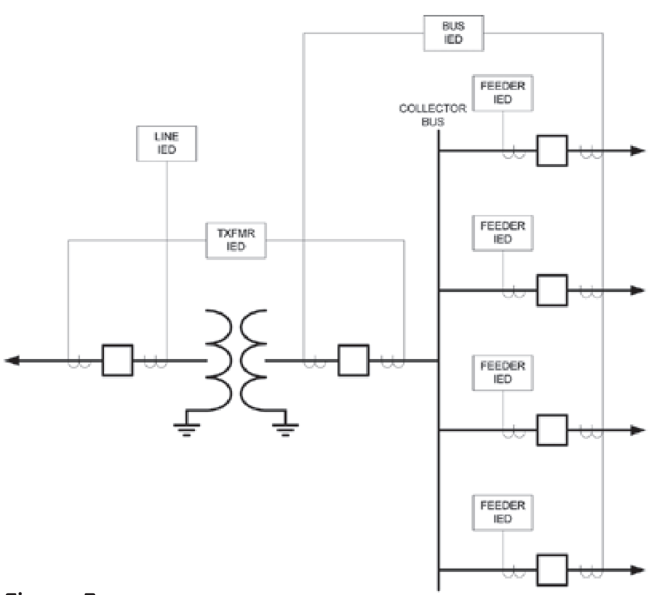

Figure 3.
Single Line of Typical Windfarm

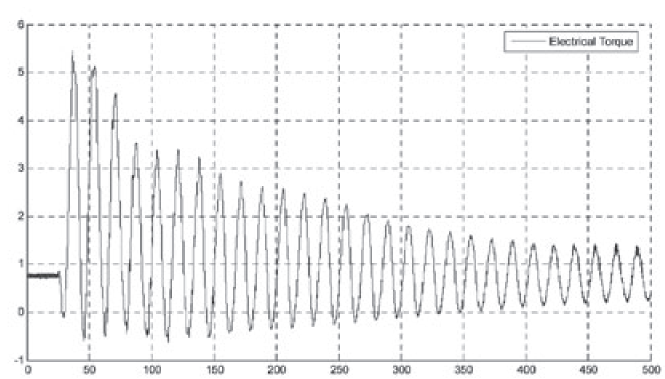

Figure 4.
Simulation of WTG Torque due to Reclosing Out-of-Phase

and first tower result in complete loss of all feeder generation, which makes it one of the least reliable.

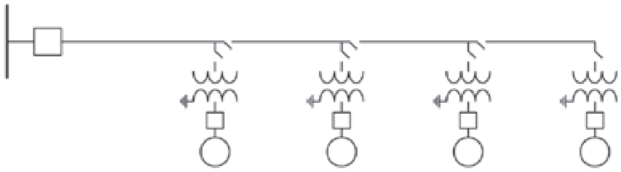

Figure 5.
Radial Feeder

Bifurcated radial topologies are similar to the radial system except they use one collector bus circuit breaker to switch two collector feeders. This configuration has the lowest installed cost base per feeder. However, it also has the lowest reliability because a breaker failure or a cable fault between the station and first tower result in complete loss of both feeders' generation.

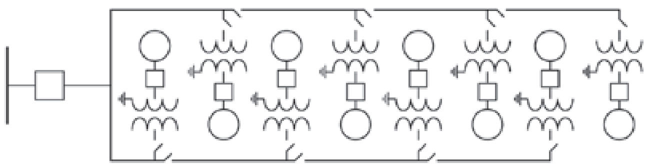

Figure 6.
Bifurcated Radial Feeder

Feeder-subfeeder topologies are typically employed where clusters of towers are distributed over large areas. They are typically comprised of a single cable feeding remotely located switchgear with several subfeeders.

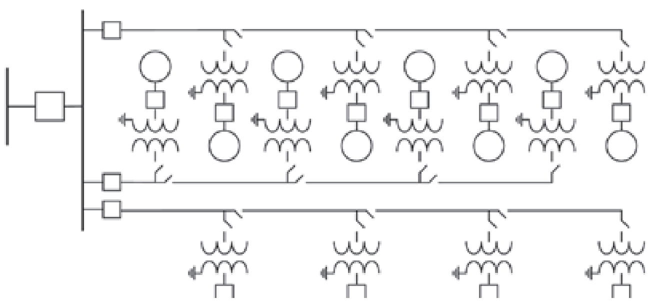

Figure 7.
Feeder-Subfeeder

Looped feeder topologies provide a higher level of availability when compared to the others. It allows continued production in the event of single component failures. Faults in the WTG tower or between towers can be isolated, allowing the remaining WTGs to continue production.

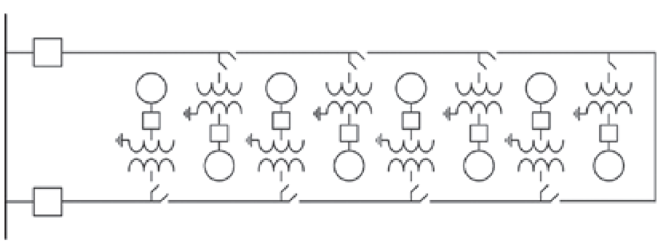

Figure 8.
Looped Feeder

5. Limitations of Typical Windfarm Topology

All windfarm topologies have an inherent limitation common to the collector bus – feeder arrangement. The windfarm topology is connected to a collector bus and stepped up to transmission level voltage through a power transformer. The windfarm feeders rely on the substation transformer neutral-ground connection for a reference ground for the medium voltage collector system. The WTGs cannot provide a reference ground because of the WTG transformer delta connection. A grounded WYE connection would introduce multiple sources of ground fault current that will complicate the ground fault protection and desensitize the IED at the substation.

If a feeder circuit breaker opens during operation, then that feeder and the operating WTGs will become isolated and form an ungrounded power system. This condition is especially troublesome if a phase-to-ground fault develops on the feeder; a scenario that causes the unfaulted phase voltages to rise to line voltage levels. It should be pointed out that a feeder ground fault is the most commonly anticipated fault type for on-shore windfarms that use overhead lines for the feeders. This fault can also result in severe transient overvoltages, which can eventually result in failure of insulation and equipment damage.

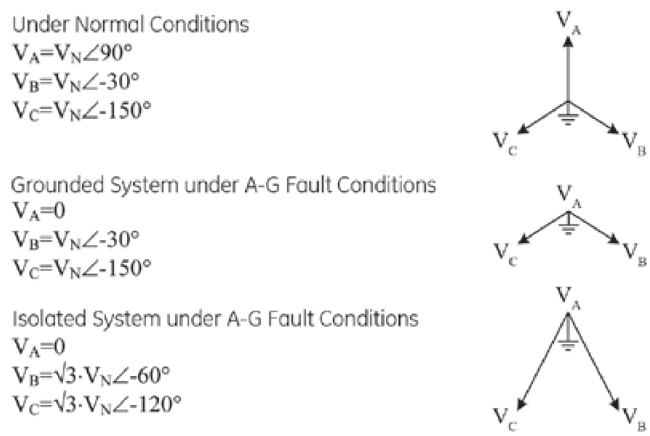

Figure 9.
Relationship for Normal and Fault Conditions

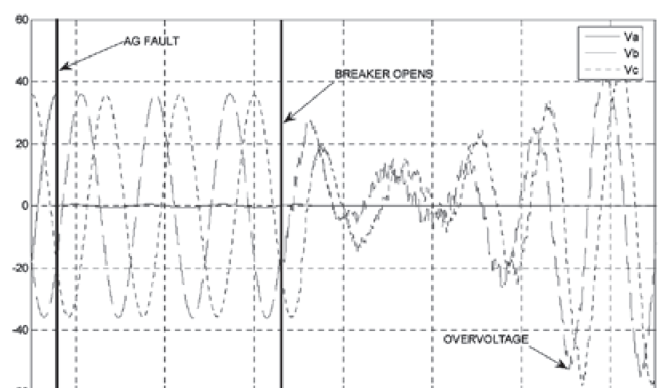

Figure 10.
Simulation of Feeder Overvoltage During a Ground Fault

Ignoring this condition could produce eventual failure of a cable or WTG transformer. One remedy is to design for the ungrounded system. This results in increased costs due to the higher voltage ratings, higher BIL, and added engineering. Another solution is to install individual grounding transformers on each feeder. This adds to equipment and engineering costs and increases the substation footprint.

6. Coordinated Fault Clearance via Transfer Tripping

An alternative solution is to disconnect the WTGs from the feeder before tripping the feeder breaker. However, the IED protecting the feeder in the substation is the only IED that can selectively detect feeder faults. In this case this IED would then send a transfer trip to all WTGs on the feeder. Once all units are disconnected, opening of the feeder breaker results in a well-behaved collapse of the voltage. Opening of the feeder breaker would be delayed minimally to ensure coordinated tripping.

7. Transfer Trip Implementation

The proposed method for implementation of the transfer trip solution is IEC61850 GOOSE messaging over a fiber-optic Ethernet network. This solution supports critical signaling to multiple IEDs. IEDs connect directly to the network, removing the need for expensive teleprotection equipment. Windfarms are often designed to include an integral network of optical fiber. Off-the-shelf Ethernet switches are available that can be configured to the existing fiber layout and can easily accommodate the distance between IEDs. As an added benefit, fiber-optic media provides excellent immunity to noise or ground potential differences.

Adoption of the IEC61850 protocol allows the same communication path to be utilized to transmit a variety of additional data. Examples of this information include control commands between devices for issuing of trip from other substation protections, commands to preclude a device from otherwise tripping (blocking), interlocking the control of a device with status of another device, event and diagnostic information (such as waveforms and event logs), and analog information (such as current and power metering).

This protocol supports several important features that make it an appropriate choice for this application. Any data items in the IED that are available via IEC61850 are structured according to the protocol and include standardized descriptions of the source and type of the data. The IEC GOOSE message carries a "user defined" dataset. The dataset can be configured with IEC61850-modeled data items. The methodology promotes ease-of-configuration and interoperability between various manufacturers IEDs.

GOOSE is a multicast message that, once transmitted can be received by any device on the network that needs it. A feature supported in the IEC GOOSE is the ability to restrict the flow of data to a particular broadcast domain through the creation of a Virtual Local Area Network or VLAN. This dataflow restriction is achieved by adding 4 bytes to the Ethernet data frame per the IEEE802.1Q standard (Figure 8). A 2-byte Tag Protocol Identifier identifies the extended data frame. The other 2 bytes include 12 bits for a VLAN ID, 3 bits for priority encoding of the Ethernet message, and one bit for backward compatibility with Token Ring. Once identified as an extended Ethernet frame, a switch in the network can decode the VLAN ID or VID. This ID is read by the network device and "switched" to those ports programmed with the same VLAN ID.

Another area addressed by the IEC GOOSE is that of Ethernet Priority. Ethernet communication has been traditionally described as "non deterministic" in that the possibility of collisions on the wire made it difficult to determine the delivery time of the message. The use of Layer 2, full-duplex switch technology now prevents the occurrence of Ethernet collisions. Switches receive all messages and store then forward them to the destination locations as required. It is possible for a single port in the switch to have several messages queued for delivery to a device. This would add a certain amount of delay in the processing of a message. Ethernet Priority, however, removes this delay. Upon receipt of an Ethernet message with a "high priority", the message is moved to the front of the queue and becomes the next message to be sent to the receiving device thereby minimizing the transmission time of the message.

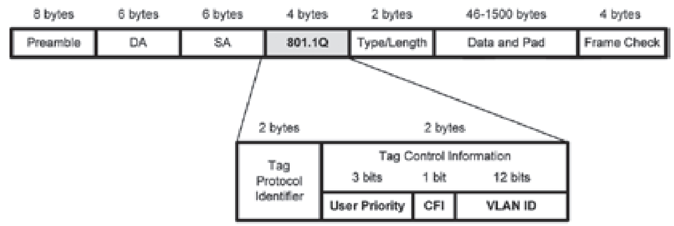

Figure 11.
Extended Ethernet Frame

The diagram below shows how the IEC61850 network topology would be deployed for a larger, radial windfarm;

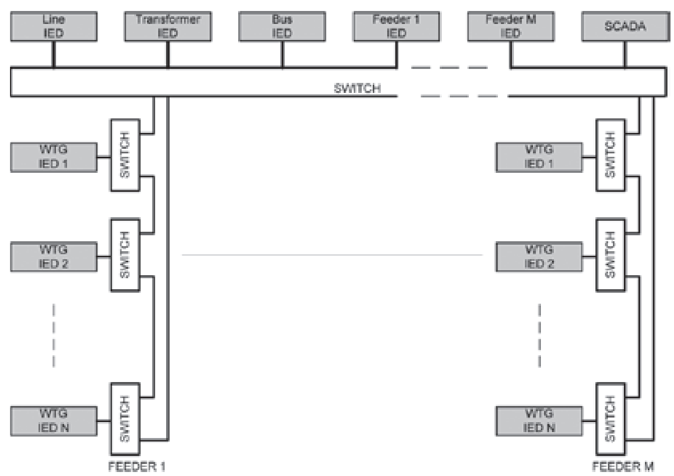

Figure 12.
Windfarm Communications Network Topology

Each wind turbine has a multifunction protection IED that would provide electrical fault protection for the generator and tower cable, as noted above. In addition to providing "local" protection for wind turbine equipment, the WTG IED features IEC61850 protocol support so as to provide the transfer trip capabilities.

The physical arrangement of the components of the windfarm dictates a network arranged in a ring-architecture for each feeder. In an Ethernet network, it is not permissible to have more than one path to a particular device. Therefore ring topologies could not be configured with early generation switches. However the latest generation of Ethernet switches provides support for Rapid Spanning Tree Protocol (RSTP). RSTP enabled switches exchange information to ensure that only one switch provides a path to a device. If a failure occurs in the enabled path, the switches will automatically reconfigure the network to re-establish a path to the device in as little as 5 milliseconds. The ring topology allows for the failure of any one path with no loss of communications to any device. A single switch failure results in the loss of communications to only one device. However, its peers on the network will quickly detect the loss of this device. This would allow the IEDs to automatically adapt to the communications failure. For instance The WTG IED could enable voltage tripping only in the case that communications with the feeder IED is lost.

8. Transfer Tripping Performance

Table 1 illustrates timing sequence for a feeder fault using the transfer trip solution. The timing analysis above assumes a breaker clearing time of 60 ms. The time required to process and transmit the GOOSE message across the network is 8 ms. Tripping of the feeder breaker by the IED is delayed by 30 ms to ensure that all of the WTGs are disconnected prior to clearing the fault. The Ethernet switches present a negligible time delay and is not included in Table 1.

Event #	Description	Time (ms)
1	Feeder Ground Fault	0
2	Feeder IED detects fault and send transfer trip	32
3a	WTG IEDs receive transfer trip & operate	8
4a	WTG breakers open	60
	WTG clearing time	**100**
3b	Feeder IED time delay	30
4b	Feeder breaker opens	60
	Feeder clearing time	**122**

Table 1.
Transfer Trip Timing

Another application would be for the WTG IED to issue a "block" command upon detection of a fault condition within the wind turbine transformer or tower cable. If such a fault occurs, the potential to cause nuisance tripping on the feeder can occur. IED2, as seen in Figure 1, provides protection for the wind tower transformer and cable, and can simultaneously trip the MV breaker as well as send a block command to the feeder IED located in the substation. This block command allows for the feeder to stay on-line and avoids disconnecting the remainder of the WTGs.

In addition to transfer trip and blocking commands, the network architecture also enables the windfarm operator to take advantage of the detailed diagnostics and metering capabilities inherent in the WTG IEDs. The current generation of microprocessor based protective IEDs contain detailed event logs, current/voltage waveform recorders, metering and other diagnostic information that prove valuable in the diagnosis of fault and system disturbances.

9. Summary

It has been demonstrated in this paper that there are aspects of a windfarm configuration that require consideration when designing the protective system. One important aspect is the need to disconnect the WTGs before isolating the feeder during a ground fault. A novel method has been presented that achieves this, alleviating the need for a grounding source on each feeder. This reduction in equipment translates into increased system reliability as well as significant cost savings for the windfarm operator. This solution makes extensive use of GOOSE messaging and leverages pre-existing system components, specifically fiber Ethernet between wind turbines, industrialized Ethernet switches and IEC61850 compliant IEDs. GOOSE messaging can also be extended to various other protection, automation, and operational applications.

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Distance Relay Fundamentals

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General Electric Co

1. Introduction

Distance functions have been in use for many years and have progressed from the original electromechanical types through analog types and now up to digital types of functions. The purpose of this paper is to discuss fundamental features of the three types of functions and possible problems that may be encountered in their design and application.

2. MHO Functions

Simple MHO Function

A simple mho distance function, with a reach of Z ohms, is shown in Figure 1. This diagram is exactly equal to an R-X diagram except that all of the impedance vectors have been operated on by the current I. The mho function uses the current and voltage measured at the relay to determine if the apparent impedance plots within the mho characteristic. The determination is made by comparing the angle between the operating quantity (IZ - V) and the polarizing quantity (V, where $V = IZ_f$). If the angle is less than or equal to 90°, then the fault impedance Z_f plots within the characteristic, and the function will produce an output. If the angle is greater than 90°, then Z_f falls outside of the characteristic and no output will be produced. Assume that the angle of maximum reach (Θ) and the angle of Z_L (Φ) are equal. On that basis, the conditions shown in 2 will be obtained. The key point to note in this phasor analysis (a convenient way to view relay performance) is the magnitude of the IZ - V (V_{op}) phasor and its relationship to the V (V_{pol}) phasor. Operation will occur whenever V_{op} and Vpol phasors are within 90° of each other and provided both V_{op} and V_{pol} are greater than the minimum values established by the sensitivity of the relay design. For the balance point fault, IZ-V is zero, therefore no operation occurs, which is expected. For an internal fault, IZ -V and V are in phase, therefore the function operates as expected. For the external fault, operation does not occur because IZ-V and V are 180° out of phase. Observe that for the balance point fault, the V is exactly equal to IZ. This is true for the three-phase fault shown (also for a phase-to-phase fault) and for a phase distance function only. For a ground distance function, this will only be true if the function includes zero sequence current compensation as discussed later in this paper.

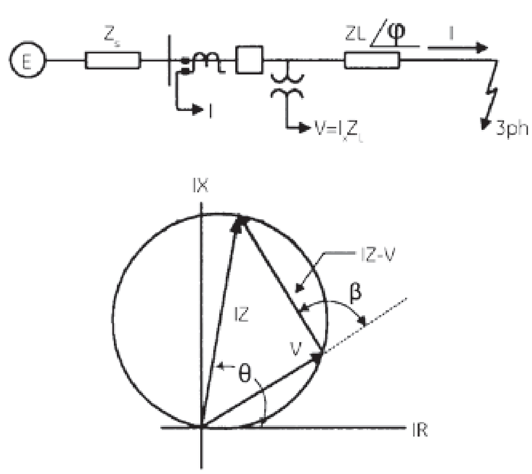

Figure 1.
Simple MHO Function.

The polarizing quantity for this simple mho distance function is simply equal to the fault voltage V, therefore the function is said to be self-polarized and has the simple characteristic shown in Figure 1. In general, a voltage different than the fault voltage is used to polarize the function and this will have an effect on the characteristic.

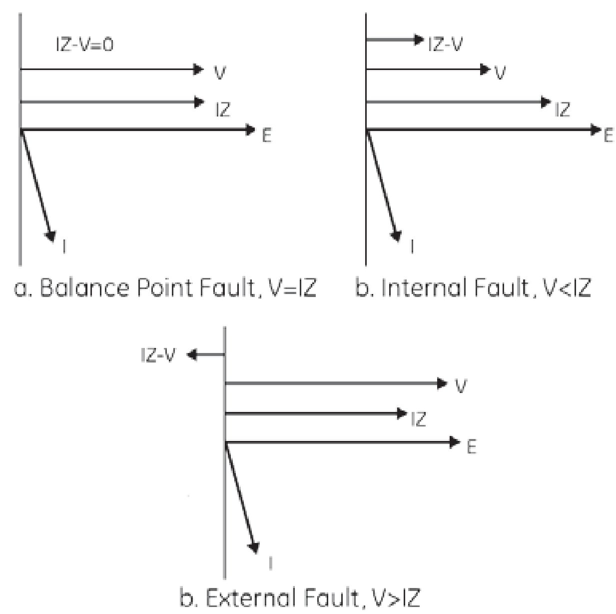

Figure 2.
Phasor Analysis of Operation of Simple MHO Function.

Polarizing Quantity

A number of polarizing quantities have been used in developing phase and ground mho distance functions. Following are some of the more commonly used:

- self-polarized (V_a for Phase A function, V_{ab} for the Phase AB function, etc.)
- positive Sequence Voltage (V_{a1} for Phase A function, V_{ab1} for Phase AB function, etc.)
- quadrature Voltage (V_{bc} shifted leading 90° for Phase A function)
- median (midpoint of V_{bc} to V_a for Phase A function)
- leading phase (V_c shifted leading 240° for Phase A function)

An mho function that is other than self-polarized is often described as being cross-polarized. No attempt will be made here to describe

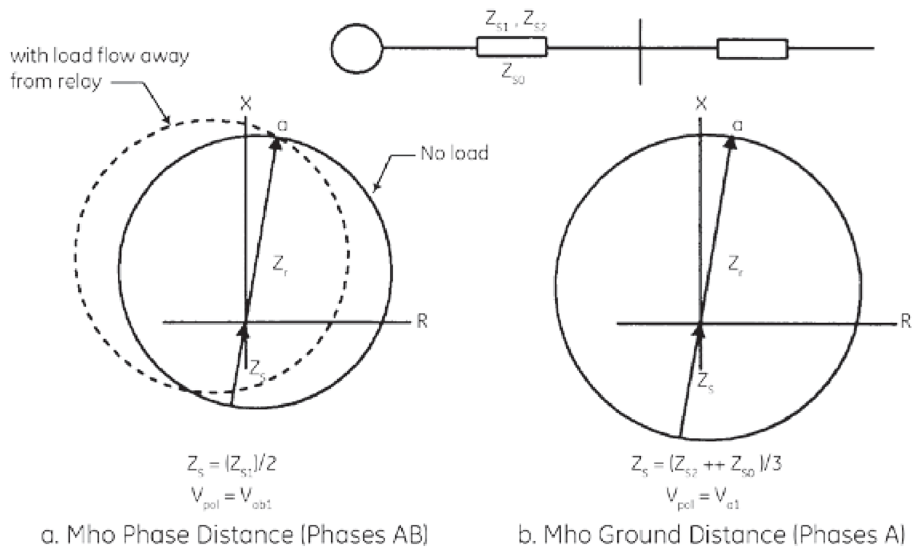

Figure 3.
Variable MHO Characteristic (positive sequence voltage polarized).

the effect of all types of cross-polarization. Suffice it to say that cross-polarization will still result in a circular characteristic, but one that may also swivel and vary in size dependent on system conditions.

For example, consider the case of a distance function that uses positive sequence voltage as the polarizing signal. The characteristics for a phase distance function and a ground distance function that use positive sequence voltage polarization are shown in Figure 3a and 3b are drawn for a phase to-phase and phase-to-ground fault respectively. As can be seen, these characteristics are not fixed in size, but will vary proportionately with the source impedance directly behind the function. Load flow [1] will cause the characteristic to swivel to the left (as shown) or to the right relative to the forward reach (point a), with the amount and direction of the swivel depending on the magnitude and the direction of load flow. The effect of the swivel and variability is to accommodate more resistance in the fault (to be discussed later) than would be obtained with a self-polarized mho function. Note that the plots of Figure 3 are for faults in the forward (tripping) direction. The function will not operate for an inductive fault behind them.

All mho distance functions require voltage in order to operate. For a fault right at the relay location, the voltage will be very small (approaching zero for a bolted fault), and a self-polarized mho function may not operate for such a fault, whereas a cross-polarized function will, except for a three-phase fault. For a three-phase close-in fault, all three voltages will be very small, therefore operation of any of the cross-polarized functions will be jeopardized because there will be very little, or no voltage available to develop the polarizing quantity. To overcome this deficiency, memory is added to the polarizing circuits.

Memory Action

In electro-mechanical and analog type mho functions, memory is accomplished through the use of tuned filter circuits. The circuits are tuned to the power system frequency and in effect remember the voltage seen by the function prior to the fault. The filters are designed with a factor sufficient to allow mho function operation until the memory dies away; i.e., during the filter ring-down period typical filter outputs lasts in the order of three to five cycles of power system frequency, which is sufficiently long to allow the function to produce an output and so initiate zone 1 direct tripping or high speed pilot tripping. Time-delayed backup tripping could not be counted on for close-in faults however, because the filter ring-down time is generally not long enough to allow the backup timers to time out.

Memory in digitally implemented mho functions is accomplished using digital techniques, consequently there is no ring-down as with analog filters, and the remembered voltage can be held for any desired period of time. If the remembered time is set long enough, then time-delayed backup tripping can also be initiated for close-in faults. In general, It is best to allow the voltage applied to a mho function to adapt to the system voltage as soon as possible following a system disturbance so that the function is in step with the system when the disturbance is cleared. For example, consider a fault of sufficient duration so that the voltage at the relay may have shifted considerably as the result of a system swing caused by the fault. If the memory is set long enough such that the function is still sensing the voltage prior to the disturbance when the disturbance is cleared, then problems may be introduced. To avoid any possible problems, memory time should be kept to a minimum, or an adaptive memory can be used. An adaptive memory can be implemented by sensing the voltage at the time of the fault. If the voltage is less than a set value (10 percent for example) then the voltage prior to the fault will be remembered and used by the function until the fault is cleared as indicated by reset of the function. On the other hand, if the voltage is greater than the set value, then the voltage prior to the fault will be remembered for a short period of time (5 cycles for example) after which the voltage applied to the function will adapt to the actual voltage. In this way, time-delayed backup protection can be implemented for close-in faults while allowing the function to change to the system voltage with minimum time delay for all other faults.

The result of memory action is to produce a dynamic (time varying) response from the function that is different from the steady-state response. This results in the dynamic and steady-state characteristics shown in Figure 4 (remember that this diagram is the same as an R-X diagram except for the inclusion of the current I). This difference in response comes about because the function is using a different polarizing voltage during the memory period as opposed to that used steady-state. The dynamic characteristic lasts as long as the memory time. If the memory

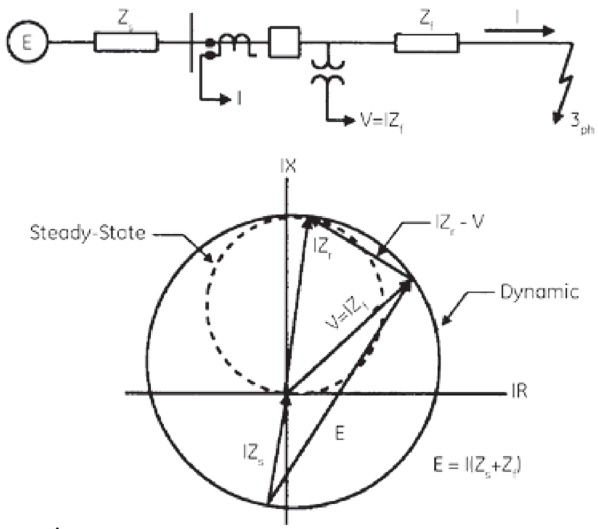

Figure 4.
Dynamic Response.

changes with time, as would happen with an analog filter, then the dynamic characteristic changes in time as the remembered voltage changes to the steady-state value. In terms of Figure 4, the function produces the dynamic characteristic using the remembered voltage, E, and then changes to the actual voltage, V to produce the steady-state characteristic. The function in Figure 4 would theoretically operate dynamically because the fault impedance (Z_f) just falls on the characteristic, but it would not operate steady-state because Z_f falls outside of the steady-state characteristic.

Polarizing Voltage Sensitivity

All distance functions require a finite amount of voltage in order to operate. Exactly how much is required is a measure of the sensitivity of the function and is determined by the type and design of the function.

The voltage polarizing sensitivity is set by design and if the voltage at the relay falls below that level then the function will not produce an output except by memory action. If there is no memory, then there will be no output. If the memory is finite in duration, then the output will last just as long as the memory. If adaptive memory is used, then the output will last until the function resets following clearing of the disturbance that initiated operation of the function.

It is possible to design the relay input circuits to sense very low magnitudes of voltage: however, there are good reasons for placing sensitivity limits on the voltage polarizing circuits, the primary purpose being to prevent operation for a fault directly behind the function [2]. Consider the system shown in Figure 5. For a three-phase fault at the location shown, resistance in the arc produces a voltage at the relay that is generally accepted to be approximately 5 percent or less of the power system voltage [3, 4]. The effect of load flow is to cause a shift in this voltage relative to the relay current because the relay current (I_r) and the total fault current (I_f) are out of phase with each other. The shift in phase in the voltage is more pronounced as the impedance, Z_t, gets larger relative to the impedance, Z_s.

A relay that operates on the quantities given in 1, can be easily analyzed for the conditions of Figure 5 by using phasors as shown in Figure 6. The function will not operate dynamically because the angle (A) between Vop and the initial polarizing signal (voltage at relay prior to the fault) is much greater than 90 degrees. If the sensitivity of the voltage polarizing circuit is less than the arc drop, then the mho function will operate steady-state for the conditions shown because the angle (B) between the operating signal, Vop, and the final polarizing signal, Varc, is less than 90°. If the sensitivity of the polarizing circuit is greater than the arc drop, then steady-state operation will not occur regardless of the angle. This analysis is predicated on the memory changing from the prefault voltage to the fault voltage during some finite time period. If the fault is cleared before the memory expires, then operation will

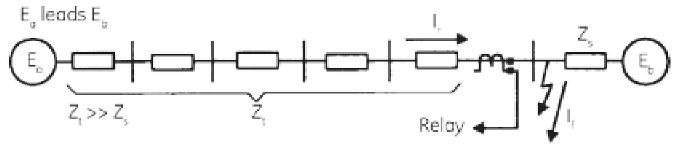

Figure 5.
Fault Behind MHO Function.

be prevented. If the memory voltage is held fixed at the prefault value, then operation for this condition will also be avoided. Note that this analysis applies for any function, self-polarized or cross-polarized for any three-phase fault, because the only voltage left to create the polarizing quantity is the arc voltage itself. For phase-to-phase, or phase-to-ground faults (assuming arc resistance only in the fault), a cross-polarized function will perform properly because the unfaulted phase voltages will be available to create a polarizing signal that will not be shifted as much in value as is the arc voltage.

Current Sensitivity

In addition to requiring a finite amount of voltage to operate, a mho distance function also requires a finite amount of current. The amount of current required is fixed by the design of the function and is related to the reach set on the function. For any given reach setting, the function will produce the set reach only for currents above a certain level. If the current is reduced below that level, then the function will start to pull back in reach until a current level is reached at which operation of the function will stop. For example, consider an electro-mechanical mho distance function in which torque must be produced to cause rotation of the element. The torque must be sufficient to overcome the inertia of the element plus the restraining spring that is used to hold the contacts open when no electrical restraining torque is being produced. Sensitivity of an electro-mechanical mho function could be found by examining the so-called bullet curve, an example of which is shown in Figure 7. From this curve, it can be seen that the amount of current required to operate the function is related to the basic ohmic reach of the function; i.e., the higher the basic reach that is selected, the lesser the amount of current required to

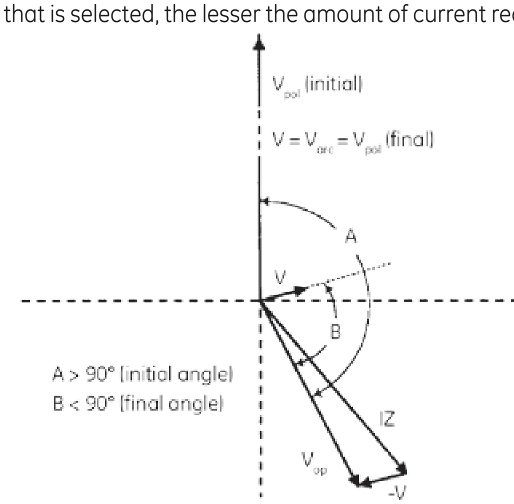

Figure 6.
Phasor Analysis of MHO.

produce operation. It is for this reason that the instruction books always recommend that the highest basic ohmic reach be used if the desired reach can be obtained through the use of any of the available basic ohmic reaches. For a 3 ohm basic reach setting, the function requires at least 1.5 amperes of current to produce operation. Note however, that the function will reach to only about 80 percent of the set reach at 1.5 amperes and that it takes about 5.0 amperes of current before the full reach will be obtained. The area between 1.5 amperes and approximately 5 amperes is referred to as the region of "pull back" because the full reach of the function is not obtained in this area. The lower portion of the curve shows the area of dynamic operation of the mho function.

Solid state and digital type mho functions do not require torque to operate and have no restraining springs to overcome. However, signal levels must be established below which the functions will not be allowed to operate. This is required to overcome errors and thresholds that are indigenous to any type of electronic equipment and design (analog or digital). Sensitivity of these types of functions can be determined from curves or through equations provided by the maker of the equipment For example, the sensitivity of one type of phase distance function can be calculated as follows:

$$I_{\phi\phi} = \frac{K}{Z_r \times (1 - X)}$$

Where,

$I_{\phi\phi}$=phase-to-phase current required to produce the actual reach

Z_r = reach setting

X = actual reach/reach setting

K = design constant

The actual reach referred to is the reach that will be obtained at the calculated current level ($I_{\phi\phi}$), taking into account any pull back. If, for example, it is desired to know the current that is required to assure that the function will reach at least 90 percent of the set reach, then X should be set equal to 0.9. Note that the current required to produce a given reach is inversely proportional to the reach setting. Longer reach settings require less current and vice versa. Functions with extremely short reaches may require a significant amount of current to produce operation and may not operate under all conditions.

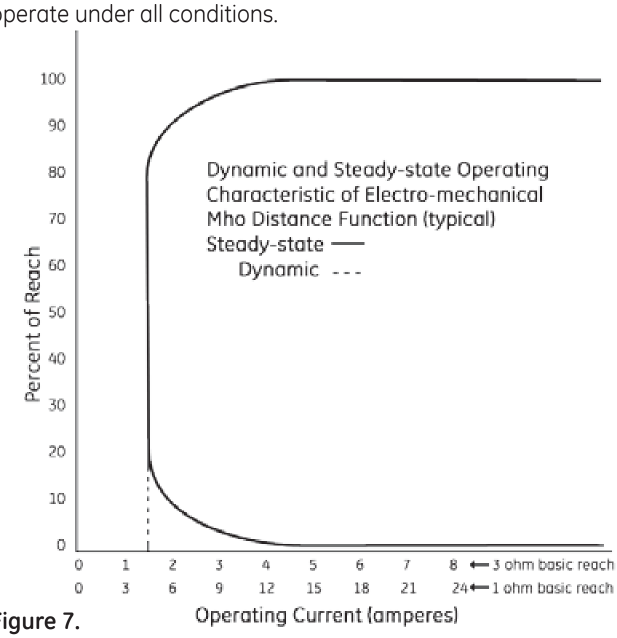

Figure 7.
Typical Bullet Curve.

Arc/Fault Resistance

For a multi-phase fault, an arc is established between the phases that results in a nearly constant voltage drop across the arc that as noted earlier is approximately equal to 4 to 5 percent of the driving system voltage. The arc appears to be purely resistive in nature and because of the constant voltage drop, the resistance varies inversely with the total current flowing in the arc. This is not strictly true for single-line-to-ground faults, wherein there may be an additional drop that is introduced through tower footing resistance, etc. If a midspan-to-ground fault occurs through a tree or fire, for example, then there could be a significant resistive component in the fault. This resistive component does not vary inversely with the current, as does the resistance in an arc, therefore, there could be a significant voltage drop across it. In any event, although the impedance of the fault is considered to be purely resistive, that does not mean that it will appear to be so to a distance function. The effect of load flow and/or non-homogeneity (system impedance angle are different) must be taken into account. This is illustrated in Figure 8.

As can be seen in Figure 8, the effect of load is to shift the resistance so that it appears to have a reactive component. The direction of the shift and the amount of shift depends on the direction and the magnitude of the load flow. System non-homogeneity has a similar effect but not nearly as severe as that caused by heavy load flow.

For a multi-phase fault, the resistance varies inversely with the current because the voltage drop across the arc is constant in magnitude. As a consequence, the system source-to-line impedance ratio becomes important in the case of multi-phase faults. As the source to line ratio increases, the voltage drop in the arc appears larger relative to the voltage drop in the line itself. The effect is to make the resistance appear to be larger relative to the line impedance as shown in Figure 9. On lines with low source-to-line ratios (typically long lines), the resistive component of the impedance seen by a distance function is very small and may be considered negligible. On the other hand, as the source-to-line ratio increases (typically short lines) the resistive component of the apparent impedance seen by the function can be quite large and can no longer be considered negligible. If the distance function is cross-polarized, then the effect of the crosspolarization will cause the characteristic to swivel in the same direction as the arc resistance itself (see Figure 3), and so preclude operation.

Infeed affects single-line-to-ground faults similarly, but because the resistance in the fault is linear, the effect can be much more dramatic. The effect of the infeed is to cause the voltage to be magnified in value so that the resistance can appear much larger than it actually is. In this case, the resistance may be so large as to render ground distance functions ineffective. For example, if the relay current, I, in Figure 8 is 1 ampere and if the fault current, If, is 10 amperes, then from equation 2 of the Figure:

$$Z = Z_L + \frac{I_f}{I} \times R = Z_L + 10R$$

As far as any distance function at the left is concerned, the fault resistance (for a ground fault with linear resistance) appears to be 10 times as large as it actually is thus increasing the chance that the function may not operate. If the fault is cleared at the right terminal, then the distance function at the left will see the true resistance at that time (If = I) and the function may operate (but not necessarily). At the right terminal of the line the effect will not be as large, and depending on the magnitude of the resistance, a ground distance function located there may or may

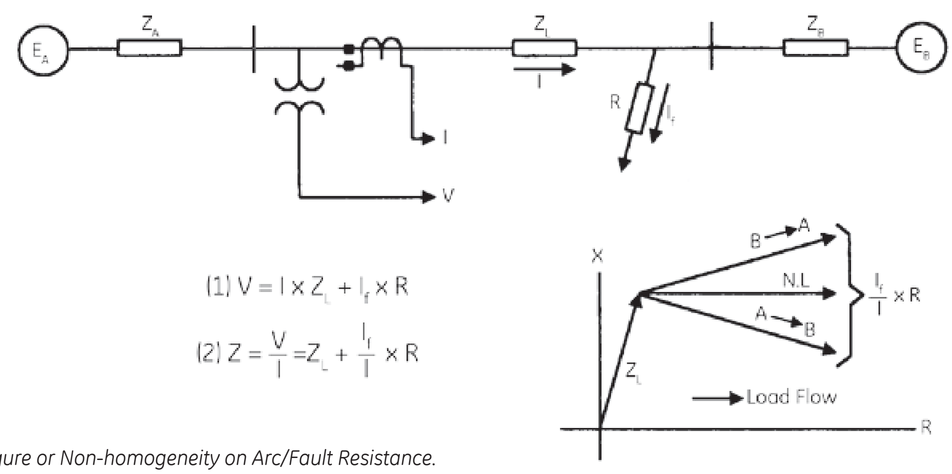

Figure 8.
Effect of Load Flow Figure or Non-homogeneity on Arc/Fault Resistance.

not operate. If the ground distance function at the right does not operate because the resistance is too large, then the fault cannot be cleared by distance relays, and ground directional overcurrent relays (or a scheme employing current alone) will have to be employed to insure clearing for high resistance ground faults.

Replica Impedance

Many solid state relay systems (and some electro-mechanical relays) use a magnetic circuit such as a transactor to develop the transmission line replica impedance. A transactor is an iron core reactor with an air gap, and it produces an output voltage that is proportional to the input current. The transfer impedance of the transactor is used to define the reach, Z, and the angle of maximum reach, Θ of the mho distance function shown in Figure 1. The transactor removes the DC component from the current signal. Digital relays may use a socalled "software implementation" of a transactor, rather than a physical transactor, to create the replica impedance. In this way, the dc component can be removed from

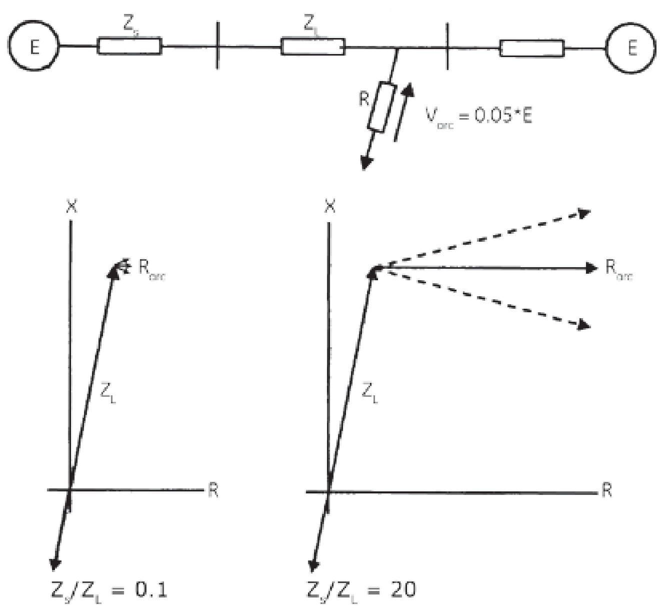

Figure 9.
Effect of Source-to Line (Z_S/Z_L) Ratio.

the current derived signal that is used in a digital relay.

In setting mho distance functions, it is desirable to match the replica impedance angle to the line impedance angle as closely as possible. In this way, the function will replicate the line voltage which will lead to an accurate measurement being made. If the replica impedance is set at an angle other than the line angle, then replication of the line voltage will be obtained only if there is no dc offset in the current. Any dc offset in the fault current will produce an error in the replicated voltage until the dc offset subsides. The error will be in the direction to promote overreaching if the angle is made lower than the line angle. Of more concern when an angle other than the line angle is used is demonstrated in Figure 10. In this application, the zone 1 function which is typically set to reach 90 percent of the line impedance, has been tipped away from the line in an attempt to obtain greater coverage for arc resistance while still maintaining a reach of 90 percent along the line angle. Greater arc resistance coverage has been obtained, but at the cost of possible overreaching for a fault at the end of the line with fault/arc resistance as shown in the Figure. While not shown, the dynamic response and the variable response of a crosspolarized mho function will exacerbate the problem because the characteristic will be expanded beyond that shown in the Figure.

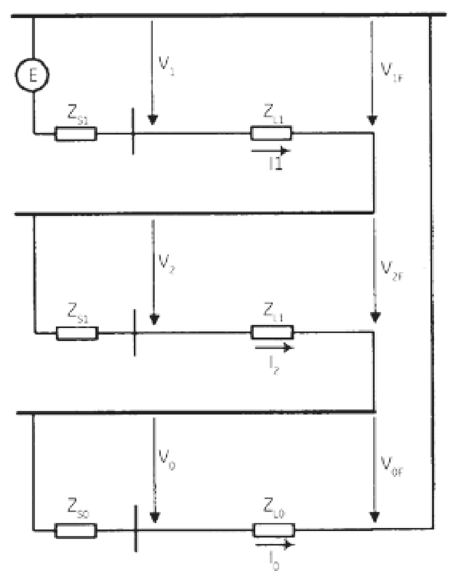

Figure 11.
Sequence Network Connections for SLG-Fault.

Zero Sequence Current Compensation

It was shown earlier for a fault at the balance point that the voltage developed in the relay would be equal to the voltage drop across along the line for multi-phase faults. This will not be true for a ground distance function during a ground fault if that function uses only the faulted phase voltage V, the faulted phase current 1, and a reach setting that is based only on the positive sequence impedance (Z_{L1}) of the line. For a phase A to ground fault at the location shown on the system of Figure 1, the sequence networks

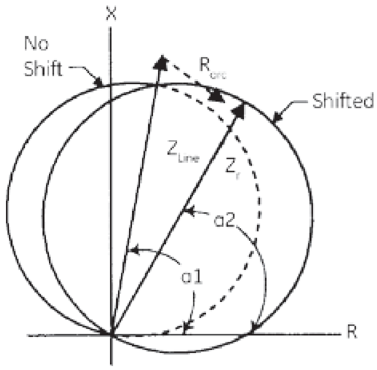

Figure 10.
Phase Shifted Function.

are connected as shown in Figure 11. The voltage at the relay (V_a) can be calculated as follows:

$V_a = V_1 + V_2 + V_0$

Where,

$V_1 = I_1 \times Z_{L1} + V_{1F}$

$V_2 = I_2 \times Z_{L1} + V_{2F}$

$V_0 = I_0 \times Z_{L0} + V_{0F}$

Therefore,

$V_a = I_1 \times Z_{L1} + I_2 \times Z_{L1} + I_0 \times Z_{L0} + (V_{1F} + V_{2F} + V_{0F})$

But,

$(V_{1F} + V_{2F} + V_{0F}) = 0$

Therefore,

$V_a = (I_1 + I_2) \times Z_{L1} + I_0 \times Z_{L0}$

The voltage at the relay, V_a, is not simply made up of the drop in the positive sequence impedance of the line as for a three-phase fault, but it also includes a factor that is proportional to the zero sequence impedance of the line and the zero sequence current seen by the relay. If a ground distance relay just uses the current I_a and is set with a replica impedance (Z_R) that is equal to the positive sequence impedance (Z_{L1}) of the line, then the IZ quantity would be as follows:

$I_a = I_1 + I_2 + I_0$

$IZ = I_a \times Z_R = (I_1 + I_2) \times Z_{L1} + I_0 \times Z_{L1}$

Note that the IZ quantity is not equal to V_a because of the difference between the positive sequence impedance and the zero sequence impedance of the line. The IZ quantity can be made equal to V_a by multiplying the zero sequence current by the ratio of the zero sequence impedance to the positive sequence impedance (Z_{L0}/Z_{L1}) of the line. If this ratio is called K_0, then a compensated current

(I_{ac}) results:

$I_{ac} = I_1 + I_2 + K_0 \times I_0$

The IZ quantity then becomes:

$IZ = I_{ac} \times Z_{L1} = (I_1 + I_2) \times Z_{Ll} + K_0 \times I_0 \times Z_{L1}$

$IZ = (I_1 + I_2) \times Z_{L1} + I_0 \times Z_{L0}$

From this, the operating quantity, Vop, can be calculated:

$V_{op} = IZ - V_a = \{(I_1+I_2) \times Z_{L1} + I_0 \times Z_{L0}\} - V_a = \{(I_1+I_2) + I_0 \times Z_{L0}\} - (I_1+I_2)$
$+ I_0 \times Z_{L0} = 0$

IZ is now exactly equal to V_a and the operating quantity IZ-V is therefore equal to zero just as was the case for the three-phase fault described earlier. K_0 is referred to as the zero sequence current compensation factor and it is used to match the zero sequence impedance of the line. The ratio of the voltage V_a to the compensated current I_{ac}, now yields:

$$\frac{Va}{Iac} = \frac{(I_1 + I_2) \times Z_{L1} + I_0 \times Z_{L0}}{I_1 + I_2 + K_0 \times I_0} = \frac{Z_{L1}\{I_1 + I_2 + (Z_{L0}/Z_{L1}) \times I_0\}}{\{I_1 + I_2 + (Z_{L0}/Z_{Ll}) \times I_0\}} = Z_{L1}$$

The effect of using K_0 therefore, is to allow the function to measure impedance in terms of the positive sequence of the line, which in turn allows the user to set the function in terms of the positive sequence impedance of the line.

Depending on the relay, the K_0 factor may also be expressed as follows:

$$K_0 = \frac{Z_{0L} - Z_{1L}}{K \times Z_{0L}}$$

Where, K can be 1 or 3 as determined by the relay design.

Regardless of how K_0 is defined, the effect on performance is the same as described above.

Operation of Ground Distance Functions for Reverse Double-Line-to-Ground Faults

As was just shown, zero sequence current compensation facilitates application of ground distance functions, but it, along with the relay reach, may also lead to an operational problem with the ground distance function associated with the unfaulted phase during a doubleline-to-ground fault behind the function (the Phase A function for a BCG to ground fault, for example). Consider the system shown in Figure 12.

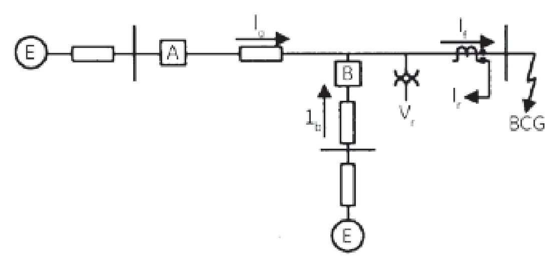

Figure 12.
BCG Fault Behind Function.

If breaker B is open, then the zero sequence current seen by the phase A ground distance function will be fed from a single source and it will be equal to the positive and negative sequence currents flowing down the line. On the other hand, with breaker B closed, the zero sequence current seen by the function can be quite large, especially if the zero sequence source behind breaker B is very strong. The effect of the strength of the zero sequence current and the relay reach can be seen by examining the operating quantity, Vop as shown in Figure 13, for the phase A distance function set with a reach of Z_R.

The phase relationship of the sequence currents as seen by the relay are shown in Figure 13a (all impedance angles were assumed to be 90° for simplicity). Note that the relay currents are 180° out of phase with those seen by the power system because the fault is behind the relay and the current transformers, when connected properly, will cause this apparent shift. The corresponding V_{op} operating phasors are shown in figures 13b and 13c for small I0 and small Z_R and large I0 and large Z_R, respectively. The polarizing quantity for this function could be the V_a voltage itself or it would

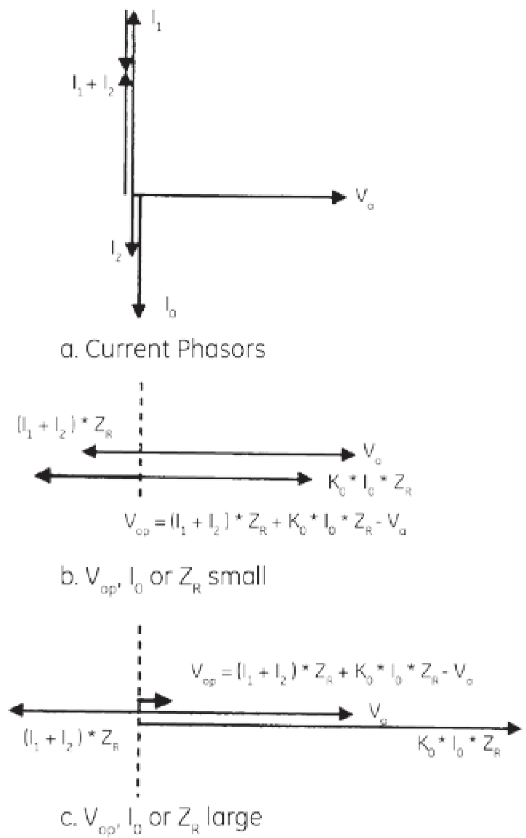

Figure 13.
Sequence Current and V_{OP} Phasor Diagrams for Reverse BCG Fault.

be a cross-polarized voltage which would be in phase with the V_a voltage. The conditions shown in Figure 13a therefore represent a non-operating condition because V_{op} and the polarizing voltage are 180° out of phase. As the zero sequence current and/or reach is increased the point will be reached where the V_{op} signal will reverse as shown in Figure 13c. This now represents an operating condition because V_{op} and the polarizing signal are now in phase.

In general, operation for this condition is minimal on two-terminal line applications unless extremely long reaches are used. The possibility is increased significantly on three-terminal line applications because of the infeed from the third terminal and also because long reaches are often used because of the effect of infeed. Ground distance functions have been designed and are available to preclude operation for this condition. Each application should be checked for the possibility of operating for this condition.

Zone 1 Ground Overreach for Remote Double-Line-to-Ground Fault

It was just shown that the ground function associated with the faulted phase could operate for an L-L-G fault directly behind the function. Another problem can occur for the same fault for a zone 1 ground distance function located at the other end of the line (terminal A). In this case it is possible for the zone 1 function associated with the leading phase [5] to overreach for a resistive fault with heavy load flowing away from the relay location (refer to reference 5 for details). Operation can be prevented for this condition through design of the function or by limiting the reach of the function. Refer to the instruction book for a specific function to see if it is designed to preclude operation without reach limitations under these conditions or if the reach must be limited to preclude operation.

Loss of Potential

Distance functions may operate during when potential is lost, but the following factors must be considered to determine what the overall effect will be:

1. The design of the function and the settings placed on it (reach, angle, etc.)
2. The magnitude and direction of load flow
3. The nature of the potential loss (full or partial)
4. The potential transformer (CVT or CCVT) connections and the total connected burden

To determine the effects of the above factors, each type of distance function must be examined separately. A phasor analysis will be provided for a self-polarized and a positive sequence polarized phase mho distance function that uses the operating principles shown in Figure 1. For this function, operation will occur when the operating quantity (V_{op} = IZ-V) and the polarizing quantity (V_{pol}) are within 90° of each other.

The phase AB function will be analyzed and unity power factor will be assumed (lagging power factor will exacerbate the problem whereas leading power factor will be less onerous). The potential connections to the function and the phasor diagrams for a total loss of potential are shown in Figure 14. For this case, the angle Θ is greater than 90° with normal potential applied, but is less than 90° after the loss of potential when V_{op} is equal to IZ and the polarizing voltage is the memorized voltage V. The function will

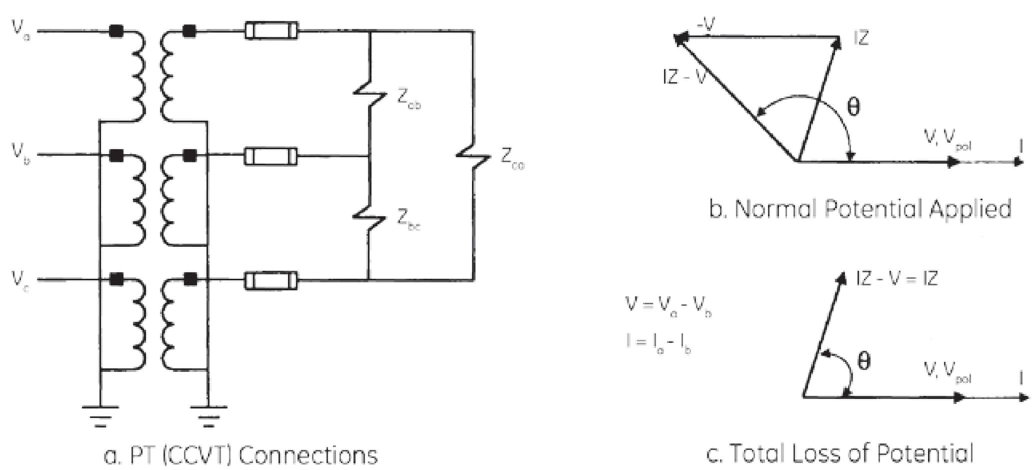

Figure 14.
Potential Connection and Phasor Diagrams for Total Loss of Potential.

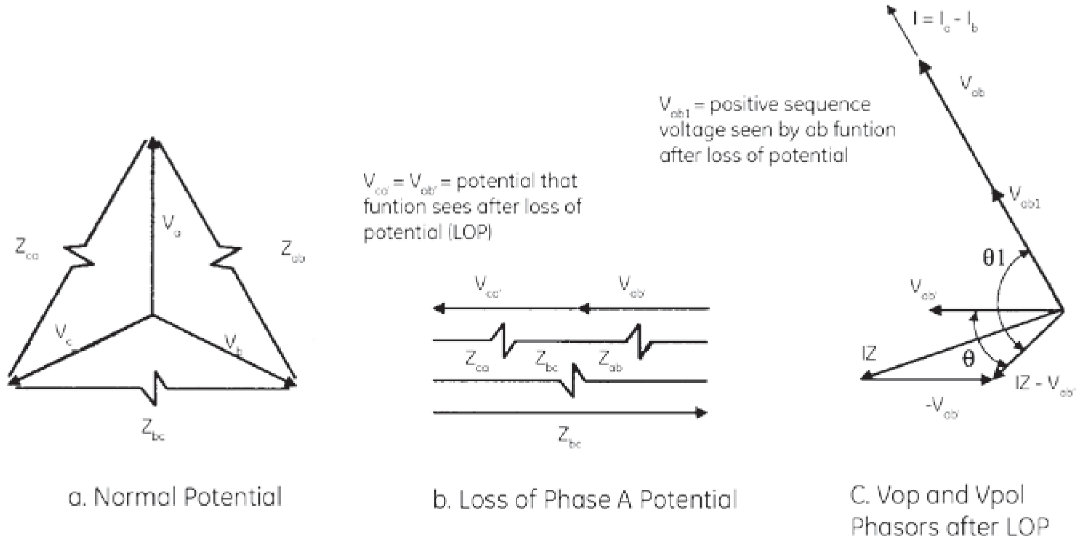

Figure 15.
Potential Connection and Phasor Diagram for Partial Loss of Potential.

therefore produce an output, and the output will last as long as the memory lasts. Unfortunately, this is generally long enough to cause a trip, especially in the case of a zone 1 function, or an overreaching function in a blocking or hybrid type of relaying scheme. Although a self-polarized function was analyzed for this example, an output will occur for the case of a total loss of potential for any phase distance function regardless of the type of polarization that is used.

The analysis for a partial loss of potential (phase A fuse blows) is shown in Figure 15. In this case, the self-polarized function will not operate dynamically, but it will operate steady-state as shown.

Because the angle Θ between V_{op} (IZ - V_{ab}') and V_{pol} (V_{ab}') is less than 90°. The positive sequence polarized function will not operate dynamically nor will it operate steady-state (angle Θ1 is greater than 90°) because the polarizing voltage Vab1 does not shift in phase although it is reduced in magnitude. Thus the positive sequence polarized function is much more secure than is the self-polarized function.

A similar type of analysis to that used above can be used to analyze the performance of any type of distance function as the result of a loss of potential.

3. Reactance Functions

A simple reactance function is shown in Figure 16. Also shown in this Figure is a so-called quadrilateral function which is in reality a reactance function. In each case, some form of supervision is required because a reactance function is inherently non-directional. Reactance type functions are often selected because of the apparent increase in resistance coverage over the traditional zone 1 function (shown dashed in the Figure). It should be remembered, however, that a crosspolarized mho function will offer resistance coverage greater than that shown because of its variable nature. Reactance type functions are susceptible to overreaching for faults with resistance in them unless the function is designed to preclude this type of operation. In addition, some quadrilateral functions may not operate for a resistive fault right at the relay location. To demonstrate the overreach problem and one way to overcome it, refer to Figure 17a and 17b.

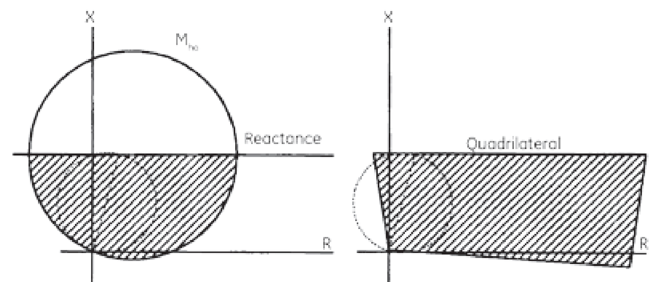

Fig 16.
Reactance Type Functions.

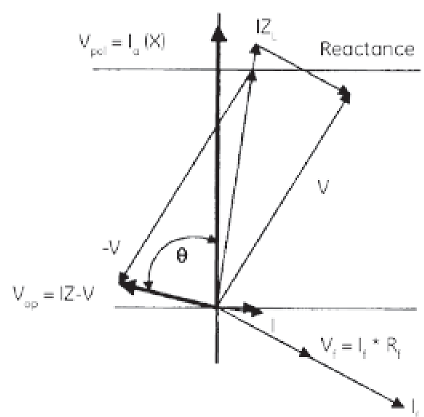

Figure 17a.
Self-Polarized Reactance Function (Ia).

Figure 17a shows a self-polarized phase A ground reactance function using the phase A current to derive the polarizing quantity. As can be seen, the effect of arc resistance and load flow (away from the relay in this example) has caused the function to overreach (Θ < 90°). For load flow in the other direction, this self-polarized function will have a tendency to underreach. The negative sequence polarized function shown in Figure 17b does not overreach for the same condition as does the selfpolarized function, nor will it underreach for load flow in the other direction. Other polarizing sources, 3I0 for example, may be used for polarizing to prevent overreaching. Further details on the performance or reactance type functions can be found in reference 1.

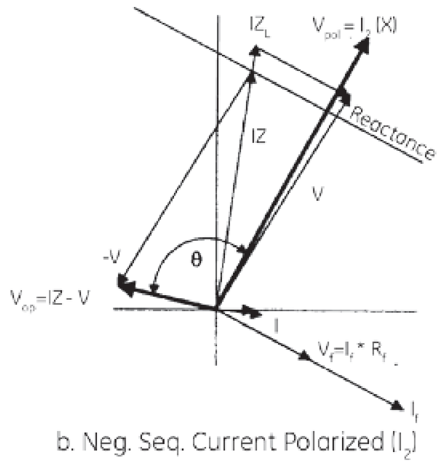

Figure 17b.
Negative Sequence Current Polarized Reactance Function (I2).

4. Coupling Capacitor Voltage Transformer (CCVT) Transients

Coupling capacitor voltage transformers are an economical way to obtain the potential required to operate distance (and directional) type relays. They also provide a means to couple communication channels to the power line for use with various relaying schemes. Unfortunately, a CCVT may not reproduce the primary voltage exactly and can introduce significant error into the distance relay measurement The transient error that is produced by the CCVT becomes more pronounced as the change in the voltage from prefault to fault is increased (a fault at the end of a line with a high source to line impedance (ZS/ZL) impedance ratio, for example). A typical CCVT transient is shown in Figure 18.

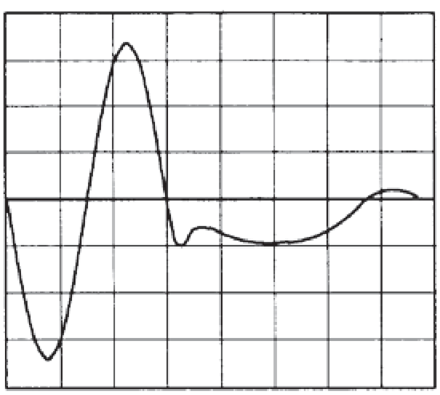

Figure 18.
Typical CVT Transient.

If a transient like this were to occur for a fault at the end of a line with a high Z_S/Z_L ratio, it could cause a zone 1 distance function to overreach. To see how this could occur, refer to Figure 19.

The operation is shown for the distance function and system of Figure 1 with the assumption that the source to line impedance ratio (Z_S/Z) is approximately 15. The ideal response shows that the function will not operate because the operating quantity, IZ-V, and the polarizing quantity, V_{pol}, are 180° out of phase. The transient response on the other hand shows that the function will operate during the second half cycle because the operating quantity and the polarizing quantity are in phase with each other (see shaded area). This example shows that care should be taken in the application of zone 1 distance functions and that the recommendation of the manufacturer should be followed in making the reach settings on the functions.

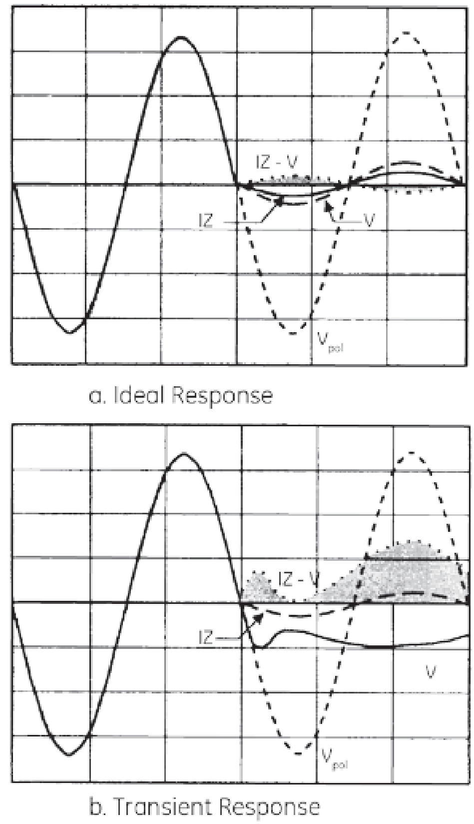

Figure 19.
Distance Function Operation for Ideal and Transient CVT Response.

CCVT transients may also cause loss of directionality for zero voltage bus faults behind the relay. The use of memory voltage and cross-polarization will reduce this tendency.

5. Conclusion

Distance functions perform a very important and essential part of many power system protective relaying systems. This paper discussed possible problem areas that can be encountered in the design and application of distance type function. It is the responsibility of the manufacturer to design relays, and to aid in their application, with these problems in mind. However, it is the ultimate responsibility of the user to insure that the relays are applied correctly.

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Application Considerations in System Integrity Protection Schemes (SIPS)

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1. Abstract

This paper describes some of the critical engineering, design, and applications of the latest technology for the implementation of System Integrity Protection Schemes (SIPS). Applicability of the advanced analytical techniques for various types of SIPS applications on the basis of modern technology is also addressed. An overview is presented of traditional scheme requirements leading to the SIPS of the future. A new survey is described in the paper, which should provide valuable information about power industry trends and experiences in SIPS.

Keywords: Power system protection, emergency control, industry practice, SIPS.

2. Introduction

The electric power grid is the "pivot point" that balances the generation and load. Maintaining the integrity of this pivot point is imperative for the effective operation of interconnected power systems. As such, the balance of power is only as reliable as the weakest pivot point in the system.

When a major disturbance occurs, protection and control actions are required to stop the power system degradation, restore the system to a normal state, and minimize the impact of the disturbance [1]. Control center operators must deal with a very complex situation and rely on heuristic solutions and policies [1], [2].

Local protection systems arrest the propagation of the fast-developing emergencies through automatic actions. Local protection systems, however, are not able to address the entire power system, which may be affected by the disturbance.

The trend in power system planning utilizes tight operating margins, with less redundancy in the grid. At the same time, addition of non-utility generators and independent power producers, an interchange increase in a growing competitive environment and introduction of fast control devices make the power system more complex to operate. This changing environment highlights the need for automated systems with advanced monitoring and intuitive interface tools to enable real-time operator interactions. On the other hand, the advanced measurement devices and communication technology in wide-area monitoring and controls,

FACTS devices (better operational and stability control), and new analytical and heuristic procedures provide better ways to detect and control an impending system collapse [3], [4], [5], [6].

Advanced detection and control strategies through the concept of System Integrity Protection Schemes (SIPS) offer a cohesive management of the disturbances. SIPS is a concept of using system information from local as well as relevant remote sites and sending this information to a processing location to counteract propagation of the major disturbances in the power system. With the increased availability of advanced computer, communication and measurement technologies, more "intelligent" equipment can be used at the local level to improve the overall response. Traditional contingency dependant / event based systems could be enhanced to include power system response based algorithms with proper local supervisions for security.

Decentralized subsystems that can make local decisions based on local measurements (system-wide data and emergency control policies) and/or send pre-processed information to higher hierarchical levels are an economical solution to the problem [7]. A major component of the SIPS is the ability to receive remote measurement information and commands via the data communication system and to send selected local information to the SCADA centre. This information should reflect the prevailing state of the power system.

This paper describes how SIPS help manage system disturbances and prevent blackouts. The design and architecture of a SIPS is addressed. The paper also discusses an effort underway to gather best practices and operational experiences globally [8].

3. Blackouts - Cause and Effect

Reviewing examples of 1996 and 2003 system blackouts worldwide [9-10] reveal some similar patterns among such disturbances. Some common causes include:

- Pre-existing conditions, such as generator/line maintenance, heavy loading.
- Tripping lines due to faults and/or protection actions resulting in heavy overloads on other lines. Protection and control misoperation or unnecessary actions, which may contribute to disturbance propagation.
- Insufficient voltage (reactive power) support.
- Inadequate right-of-way maintenance.
- Insufficient alarms or monitoring to inform operators of equipment malfunctions.
- Inability of operators to respond to impending disturbances or to prevent further propagation of the disturbance and problems with EMS/SCADA systems to provide only important information when required.
- Inadequate planning/operation studies.
- Automated actions are not available/initiated to prevent further overloading of the lines, arrest voltage decline and/or initiate automatic and pre-planned separation of the power system.

While it is not realistically possible to completely eliminate blackouts (unless very large investments are made that would make the price of electricity unreasonable for end users) the above shows that by taking some reasonably cost-effective measures, occurrence of the blackouts could be reduced. We are focusing in this paper on the last of those issues, implementation of automated actions, the purpose of which is to prevent an imminent blackout, or at least arrest its propagation and mitigate some of its undesired consequences.

4. Technology for Modern Protection

SCADA/EMS system capability has greatly improved in the last few years, due to improved communication facilities and enhanced data handling capabilities. Improved EMS/SCADA systems require the ability to filter, display, and analyze only critical information and to increase availability of critical functions to 99.99% or better. Critical alarm monitoring systems must be maintained in top operating condition, and newer alarm analysis technologies should be deployed to detect and prevent the spread of major disturbances.

Modern technology, such as phasor measurement units (PMUs) and high bandwidth and high-speed communication networks, can provide time-synchronized measurements from all over the grid [1]. Based on those measurements, improved, faster and more accurate state estimators can be developed. In addition, advanced algorithms and calculation programs that assist the operator can also be included in the SCADA system, such as "faster than real-time simulations" to calculate power transfer margins based on various contingencies.

Development of system integrity protection schemes can help manage system disturbances and prevent blackouts. Those wide area protection schemes are based on pre-planned, automatic and corrective actions, implemented on the basis of system studies, with the goal to restore acceptable system performance. Although SIPS schemes can help increase the transfer limits, their primary goal is to improve security of the power system.

As system conditions change, it is necessary to perform studies and review protection designs on a regular basis to prevent protection misoperation. In addition, as protection systems are designed to be either more dependable (emphasis on making sure that protection acts when it should) or more secure (protection does not misoperate), designers can increase the security of protection design in the areas vulnerable to blackouts. As an example, transmission line pilot protection could be migrated to Permissive Overreach Transfer Trip scheme (POTT), which is more secure, compared to the more dependable Directional Comparison Blocking (DCB) scheme.

As hidden failures have been identified to be the significant contributors to blackouts [9], adequate testing of not only individual relays, but also overall relay applications, is crucial to reveal the potential failures. As system protection is generally intended to operate for rare events, and at the same time to mitigate a large number of potential disturbance conditions, a well developed automated testing plan which verifies inputs, logic, and output, is critical for proper maintenance of the scheme.

5. SIPS: Design and Architectures

The SIPS encompasses Special Protection Schemes (SPS), Remedial Action Schemes (RAS), as well as additional schemes such as, but not limited to, Underfrequency (UF), undervoltage (UV), out-of-step (OOS), etc., Figure 1.

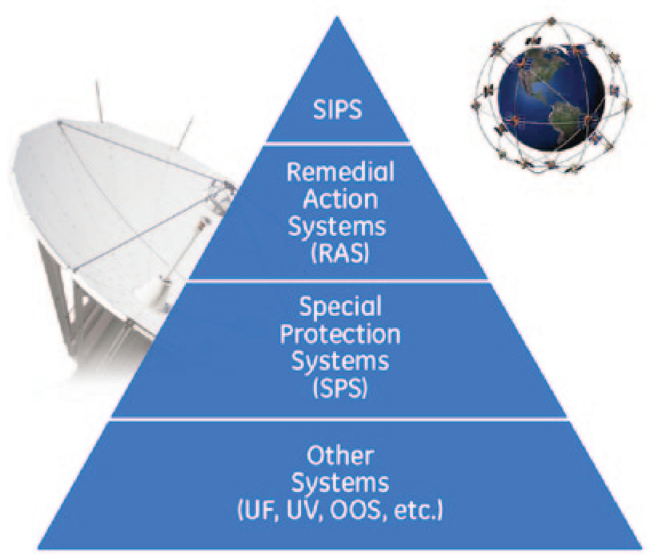

Figure 1.
SIPS, A Set of Automatic, Synchronized, and Coordinated Counter Measures

SIPS are installed to protect the integrity of the power system or its strategic portions. A SIPS is applied to the overall power system or a strategic part of it in order to preserve system stability, maintain overall system connectivity, and/or to avoid serious equipment damage during major events. Therefore, the SIPS may require multiple detection and actuation devices and communication facilities. Figure 2 shows SIPS classification.

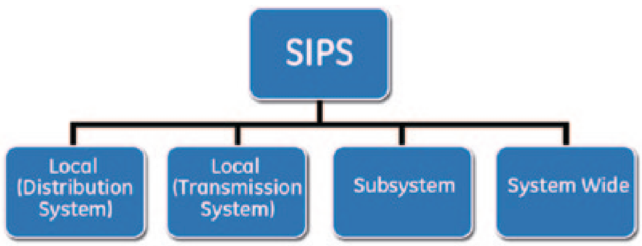

Figure 2.
SIPS Classification

SIPS classifications have been defined through a collective global industry effort by members of the IEEE and CIGRE [8]. Below is a summary.

Local (Distribution System) – SIPS equipment is usually simple, with a dedicated function. All sensing, decision-making and control devices are typically located within one distribution substation. Operation of this type of SIPS generally affects only a very limited portion of the distribution system such as a radial feeder or small network.

Local (Transmission System) - All sensing, decision-making and control devices are typically located within one transmission substation. Operation of this type of SIPS generally affects only a single small power company, or portion of a larger utility, with limited impact on neighboring interconnected systems. This category includes SIPS with impact on generating facilities.

Subsystem - The operation of this type of SIPS has a significant impact on a large geographic area consisting of more than one utility, transmission system owner or generating facility. SIPS of this type are more complex, involving sensing of multiple power system parameters and states. Information can be collected both locally and from remote locations. Decision-making and logic functions are typically performed at one location. Telecommunications facilities are generally needed both to collect information and to initiate remote corrective actions.

System Wide - SIPS of this type are the most complex and involve multiple levels of arming and decision making and communications. These types of schemes collect local and telemetry data from multiple locations and can initiate multi-level corrective actions consistent with real-time power system requirements. These schemes typically have multi-level logic for different types and layers of power system contingencies or outage scenarios. Operation of a SIPS of this type has a significant impact on an entire interconnected system.

Failure of the SIPS to operate when required, or its undesired or unintentional operation will also impact balanced power system operation. Therefore, design of the SIPS may involve redundancy or some backup functions, and depending on the operational security requirements, may involve some form of voting or vetoing (fail-safe) based on the intended design.

The scheme architecture can be described by the physical location of the sensing, decision making, and control devices that make up the scheme and the extent of impact the SIPS has on the electrical system. SIPS are classified into two main types of architectures: flat and hierarchical.

Flat Architecture - the measurement and operating elements of the SIPS are typically in the same location. The decision and corrective action may need a communication link to collect remote information and/or to initiate actions.

Hierarchical Architecture - There are several steps involved in the SIPS corrective action. For example, local measurement, or a series of predetermined parameters at several locations are transmitted to multiple control locations. Depending on the intent of the scheme, immediate action can be taken and further analysis performed. The scheme purpose will drive the logic, design, and actions. Typical logic involves use of operating nomograms, state estimation and contingency analysis.

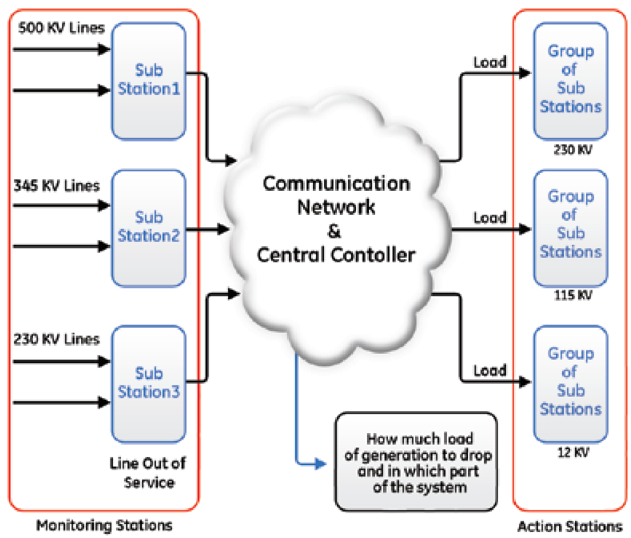

Figure 3.
System Protection Terminal [12]

The design should address all standard requirements for protection terminals [13], [14]. The terminal is connected to the substation control system. For time tagging applications, a GPS-based synchronization function is needed, Figures 1 and 3. The system protection terminal possesses a high-speed communication interface to transfer data between the terminal databases, which contain all updated measurements and binary signals recorded in that specific substation. The conventional substation control system is used for the input and output interfaces with the power system. The decision-making logic contains all the algorithms and configured logic necessary to derive appropriate output control signals, such as circuit-breaker trip, AVR-boosting, and tap-changer action, to be performed in that substation. The input data to the decision-making logic is taken from the continuously monitored data, stored in the database. A low speed communication interface for SCADA communication and operator interface should also be available as an enhancement for the SCADA state estimator. Actions ordered from SCADA/EMS functions, such as optimal power flow, emergency load control, etc., could be activated via the system protection terminal. The power system operator should also have access to the terminal, for supervision, maintenance, update, parameter setting, change of setting groups, disturbance recorder data collection, etc.

For local schemes, where monitoring and decision stations are within close proximity, there may still be a need for use of high-speed communication. Details of an extremely high speed vetoing scheme involving major generation and coordination against various types of protection schemes including out-of-step protection has been described in [13].

6. SIPS or RAS Application Definitions

The types of SIPS applications may vary based on the topology of the power grid. There may also be different views on the acceptability of the type of the application. For example, use of SIPS for generation shedding to balance grid performance may be viewed as unacceptable for certain levels of contingency in one network but a common practice in another interconnected grid. Consider power systems with limited transmission corridors where building a redundant and diverse interconnection outlet for a generating facility may not be physically practical or economically feasible to address variety of technically possible outlet outages. In such conditions, the generator owner may accept a certain level of risk so long as it can be demonstrated that such SIPS does not result in an unacceptable level of security for to other parts of the grid.

Table 1 shows the types of wide-are disturbances likely to occur in two different types of interconnected power grids, namely meshed network vs. an interconnected transmission system of narrow corridors consisting of extensive generation tied to the interconnection.

System Configuration	Densely meshed power system with dispersed generation and load		Lightly meshed transmission systems with localized generation and load	
Events	Located in a large interconnection	Not interconnected or by far the largest partner	Located in a large interconnection	Not interconnected or far the largest partner
Overloads	**	**	*	*
Frequency instability	*	**	*	**
Voltage instability	*	*	**	**
Transient angle instability	*	*	**	**
Small signal stability	*	*	*	*

Table 1.
Types of Wide-Area Events on two Different Interconnected Transmission Systems

The characteristics of the power system influencing the types of mitigation methods have been described in a variety of literature [15-19]. The mitigation measure to maintain grid integrity are described in a document under development by a collaborative effort of IEEE, CIGRE, and EPRI [8]. Below is a summary listing of the types:

- Generator Rejection
- Load Rejection
- Under-Frequency Load Shedding
- Under-Voltage Load Shedding
- Adaptive Load Mitigation
- Out-of-Step Tripping
- Voltage Instability Advance Warning Scheme
- Angular Stability Advance Warning Scheme
- Overload Mitigation
- Congestion Mitigation
- System Separation
- Shunt Capacitor Switching
- Tap-Changer Control
- SVC/STATCOM Control
- Turbine Valve Control
- HVDC Controls
- Power System Stabilizer Control
- Discrete Excitation
- Dynamic Breaking
- Generator Runback
- Bypassing Series Capacitor
- Black-Start or Gas-Turbine Start-Up
- AGC Actions
- Busbar Splitting

7. SIPS or RAS: Industry Experience

In August of 1996, a seminal article [20] was published as a result of the activity of the joint Working Group of IEEE and CIGRE, the purpose of which was to investigate the special protection schemes then in existence worldwide and to report about various aspects of their designs, functional specifications, reliability, cost and operating experience. The report encompassed over 100 schemes from all over the world and provided a wealth of information on the direction the industry was taking in coping with ever larger disturbances.

In 2004, the System Protection Subcommittee of the IEEE Power System Relaying Committee started an initiative to update the industry experience on RAS, SPS and SIPS by creating and widely disseminating a new survey, which would attempt to attract as wide a response from the industry worldwide as the original report did. The authors of this paper are amongst the many industry recognized members that have generated a survey of industry experiences [16]. After considerable effort to incorporate in the framework of the new survey most of the advances which have occurred in the last decade, coupled by design considerations for natural calamity phenomenon such as tsunami or hurricanes, or seismic events, the revised survey has been completed and has distributed globally to professional audience with an intention to solicit as wide a response.

8. Structure of the Survey

The survey is divided into two parts: Part 1 identifies the "Purpose" of the scheme with subsections of "Type" and "Operational Experience" - For that part, a series of questions are repeated for each type of scheme which is reported.

Part 2 concerns Engineering, Design, Implementation, technology, and other related sections such as cyber security Considerations. This series of questions are asked only one time. The respondents are asked to answer those questions based on most common practice in their companies.

The survey also asks respondents to identify the system integrity protection schemes that exist on their systems, the design and implementation, and the operation experience as applicable. Results of the survey are expected to assist the respondents in:

- The application, design, implementation, operation, and maintenance of new and next generation SIPS.
- Understanding feasible alternatives applied to extending transmission system ratings without adding new transmission facilities.
- Applicability of delayed enhancement of transmission networks to the respondent's system.
- Providing reasonable countermeasures to slow and/or stop cascading outages caused by extreme contingencies (safety net).

The survey is intended for power system professionals involved in the Planning, Design, and Operation of SIPS. Specific skill required to complete the survey include, protection, telecommunication and system planning. The survey is distributed through CIGRE, IEEE, and EPRI. Among the questions found in Part II of the survey are the following issues:

- System studies done prior to deploying the SIPS
    - Planning criteria
    - Types of planning studies
    - Real-time operational studies
    - Protection and control coordination studies
- Coordination with other protection and control systems
- Types of protective relaying technology used
- Existence of standards for SIPS applications
- Hardware description and outage detection
    - Outage detection method
    - Questions on use of programmable logic controllers
- Scheme Architecture
    - Objective: decision making
    - Redundancy needs/implementation - both telecommunication and hardware
    - Redundancy philosophy
    - Questions on use of the voting schemes
    - Questions about control: event based, or response based
    - Questions on breaker failure
    - Performance requirements:
        - Throughput timing: entire scheme
        - Throughput timing of the controller
- Data acquisition and related tools
    - Measured quantities
    - Time synchronization requirements
    - Use of SMART SIPS / intelligent SIPS
    - Blocking (by the scheme) of any automatic reclosing
    - Restoration issues and planned mechanisms
- Communication, networking, and data exchange
    - Architecture of the communication
    - Communication medium and protocols
    - Information about shared communication (with other applications)
    - Impact of communication failure on reliability index and availability
    - Cyber security implementation and protection features
    - Operability of the scheme with a communication channel failure
    - Control area visibility
- Arming methodology
- Implementation issues
    - Multi-functionality of the scheme
    - Design: centralized or distributed architecture
    - Availability of event reconstruction or system playback capability
    - Description of event records and their availability within the organization
- Testing considerations
    - Testing procedure
    - Periodicity of testing
    - Maintenance issues
- Cost considerations
    - Approximate cost
    - System information (infrastructure)

The survey is currently being disseminated and responses are being collected. When sufficiently large sample of responses is received, a report will be compiled which is expected to answer many questions about current industry practices, regional differences in system protection philosophy and experience with such designs.

9. Conclusions

The paper describes some of the critical design considerations and applications of latest technology for SIPS. Applicability of the advanced analytical techniques for various types of SIPS applications on the basis of modern technology is also addressed as part of the overview. An overview is presented of traditional scheme requirements leading to the SIPS of the future. In the light of fast changing operating conditions in power systems (ever smaller security margins and transmission capacity, aging infrastructure, etc.) and quickly changing enabling technologies for power system control and protection, the industry landscape is changing quickly and adapting to the conditions imposed by new business practices. The new survey should provide valuable information to industry practitioners and researchers alike about the trends and experiences in system protection. The readers are encouraged to assist the authors in disseminating the survey across the globe for maximum impact.

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The Evolution of Distribution

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GE Energy

With smart grids, confidence and expectations are high. To various degrees, utilities are putting smart grid initiatives in place, and many of the technologies that paraded under the smart grid banner are currently implemented in utilities. The smart grid initiative uses these building blocks to work toward a more integrated and long-term infrastructure. If all goes as expected, smart grids will provide tremendous operational benefits to power utilities around the world because they provide a platform for enterprise-wide solutions that deliver far-reaching benefits to both utilities and their end customers.

The development of new technologies and applications in distribution management can help drive optimization of the distribution grid and assets. The seamless integration of smart grid technologies is not the only challenge. Also challenging is the development and implementation of the features and applications required to support the operation of the grid under the new environment introduced by the use of clean energy and distributed generation as well as the smart consumption of electricity by end users. Distribution management systems and distribution automation applications have to meet new challenges, requiring advances in the architecture and functionality of distribution management, i.e., an advanced distribution management system (DMS) for the smart grid.

1. Current Distribution Management Systems

Distribution Management Systems (DMSs) started with simple extensions of supervisory control and data acquisition (SCADA) from the transmission system down to the distribution network. A large proportion of dispatch and system operation systems in service today rely on manual and paper-based systems with little real-time circuit and customer data. Operators have to contend with several systems and interfaces on the control desk ("chair rolls") based on multiple network model representations. The experience of operators is key to safe system operation. With an increase in regulatory influence and the focus on smart grid advanced technologies, there is a renewed interest in increasing the investment in distribution networks to defer infrastructure build-out and to reduce operating and maintenance costs through improving grid efficiency, network reliability, and asset management programs.

Various DMS applications are commonly used today.

- Fault detection, isolation, and service restoration (FDIR) is designed to improve system reliability. FDIR detects a fault on a feeder section based on the remote measurements from the feeder terminal units (FTUs), quickly isolates the faulted feeder section, and then restores service to the unfaulted feeder sections. It can reduce the service restoration time from several hours to a few minutes, considerably improving the distribution system reliability and service quality.
- Integrated voltage/var control (IVVC) has three basic objectives: reducing feeder network losses by energizing or de-energizing the feeder capacitor banks, ensuring that an optimum voltage profile is maintained along the feeder during normal operating conditions, and reducing peak load through feeder voltage reduction by controlling the transformer tap positions in substations and voltage regulators on feeder sections. Advanced algorithms are employed to optimally coordinate the control of capacitor banks, voltage regulators, and transformer tap positions.
- The topology processor (TP) is a background, offline processor that accurately determines the distribution network topology and connectivity for display colorization and to provide accurate network data for other DMS applications. The TP may also provide intelligent alarm processing to suppress unnecessary alarms due to topology changes.
- Distribution power flow (DPF) solves the three-phase unbalanced load flow for both meshed and radial operation scenarios of the distribution network. DPF is one of the core modules in a DMS and the results are used by many other DMS applications, such as FDIR and IVVC, for analyses.
- Load modeling/load estimation (LM/LE) is a very important base module in DMS. Dynamic LM/LE uses all the available information from the distribution network—including transformer capacities and customer monthly billings, if available, combined with the real-time measurements along the feeders—to accurately estimate the distribution network loading for both individual loads and aggregated bulk loads. The effectiveness of the entire DMS relies on the data

accuracy provided by LM/LE. If the load models and load values are not accurate enough, all the solution results from the DMS applications will be useless.

- Optimal network reconfiguration (ONR) is a module that recommends switching operations to reconfigure the distribution network to minimize network energy losses, maintain optimum voltage profiles, and to balance the loading conditions among the substation transformers, the distribution feeders, and the network phases. ONR can also be utilized to develop outage plans for maintenance or service expansion fieldwork.

- Contingency analysis (CA) in the DMS is designed to analyze potential switching and fault scenarios that would adversely affect supply to customers or impact operational safety. With the CA results, proactive or remedial actions can be taken by changing the operating conditions or network configuration to guarantee a minimal number of customer outages and maximum network reliability.

- Switch order management (SOM) is a very important tool for system operators in real-time operation. Several of the DMS applications and the system operators will generate numerous switch plans that have to be well-managed, verified, executed, or rejected. SOM provides advanced analysis and execution features to better manage all switch operations in the system.

- Short-circuit analysis (SCA) is an offline function to calculate the short-circuit current for hypothetical fault conditions in order to evaluate the possible impacts of a fault on the network. SCA then verifies the relay protection settings and operation, and recommends more accurate relay settings or network configuration.

- Relay protection coordination (RPC) manages and verifies the relay settings of the distribution feeders under different operating conditions and network reconfigurations.

- Optimal capacitor placement/optimal voltage regulator placement (OCP /OVP) is an offline function used to determine the optimal locations for capacitor banks and voltage regulators in the distribution network for the most effective control of the feeder vars and voltage profile.

- The dispatcher training simulator (DTS) is employed to simulate the effects of normal and abnormal operating conditions and switching scenarios before they are applied to the real system. In distribution grid operation, DTS is a very important tool that can help operators evaluate the impacts of an operation plan in advance or simulate historical operation scenarios to obtain valuable training on the use of the DMS. DTS is also used to simulate the conditions of system expansions.

2. Transformation of the Grid: Increasing Complexity

Distribution networks have not always been the focus of operational effectiveness. As supply constraints continue, however, there will be more focus on the distribution network for cost reduction and capacity relief. Monitoring and control requirements for the distribution system will increase, and the integrated smart grid architecture will benefit from data exchange between the DMS and other enterprise applications. The emergence of widespread distributed generation and consumer demand response programs also introduces considerable impact to the DMS operation. Smart grid technologies will add a tremendous amount of real-time and operational data with the increase in sensors and the need for more information on the operation of the system. Utility customers will be able to generate and deliver electricity to the grid or consume the electricity from the grid based on determined rules and schedules. This means that the consumers are no longer pure consumers but sellers or buyers, switching back and forth from time to time. It requires that the grid operates with two-way power flows and is able

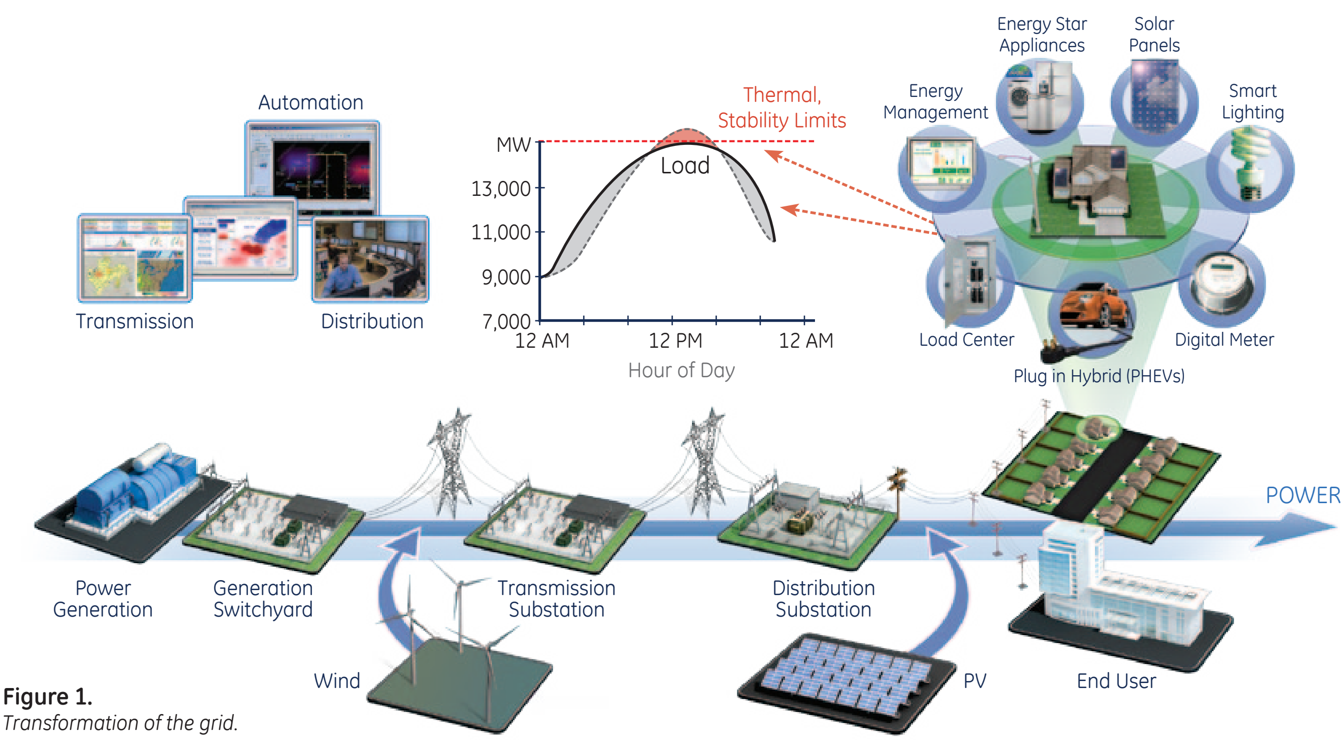

Figure 1.
Transformation of the grid.

to monitor and control the generation and consumption points on the distribution network. Figure 1 illustrates some expected transformation of the grid.

The distributed generation will be from disparate sources and subject to great uncertainty. The electricity consumption of individual consumers is also of great uncertainty when they respond to the real-time pricing and rewarding policies of power utilities for economic benefits. The conventional methods of LM and LE in the traditional DMS are no longer effective, rendering other DMS applications ineffective or altogether useless. The impact of demand response management (DRM) and consumer behaviors may be modeled or predicted from the utility pricing rules and rewarding policies for specified time periods, which can be incorporated into the LM and LE algorithms; this requires a direct link between the DMS and the DRM applications. When the DRM application attempts to accomplish load relief in response to a request from the independent system operator (ISO), it will need to verify from the DMS that the DRM load relief will not result in any distribution network connectivity, operation, or protection violations. The high penetration of distributed generation will require the load flow algorithm to deal with multiple, incremental, and isolated supply sources with limited capacities, as well as a network topology that is no longer radial or is weakly meshed. In a faulted condition, the distributed generation will also contribute to the short-circuit currents, adding to the complexity of the SCA, RPC, and FDIR logic.

3. Advanced Distribution Management Systems

A number of smart grid advances in distribution management are expected, as shown in Figure 2.

- Monitoring, control, and data acquisition will extend further down the network to the distribution pole-top transformer and perhaps even to individual customers by means of an advanced metering infrastructure (AMI) and/or demand response and home energy management systems on the home area network (HAN). More granular field data will help increase operational efficiency and provide more data for other smart grid applications, such as outage management. Higher speed and increased bandwidth communications for data acquisition and control will be needed. Sharing communication networks with an AMI will help achieve systemwide coverage for monitoring and control down the distribution network and to individual consumers.

- Integration, interfaces, standards, and open systems will become a necessity. Ideally, the DMS will support an architecture that allows advanced applications to be easily added and integrated with the system. Open standards databases and data exchange interfaces (such as CIM, SOAP, XML, SOA , and enterprise service buses) will allow flexibility in the implementation of the applications required by the utility, without forcing a monolithic distribution management solution. For example, the open architecture in the databases and the applications could allow incremental distribution management upgrades, starting with a database and a monitoring and control application (SCADA), then later adding an IVVC application with minimal integration effort. As part of the overall smart grid technology solution or roadmap, the architecture could also allow interfacing with other enterprise applications such as a geographic information system (GIS), an outage management system (OMS), or a meter data management system (MDM) via a standard interface. Standardized Web-based user interfaces will support multiplatform architectures and ease of reporting. Data exchange between the advanced DMS and other enterprise applications will increase operational benefits, such as meter data management and outage management.

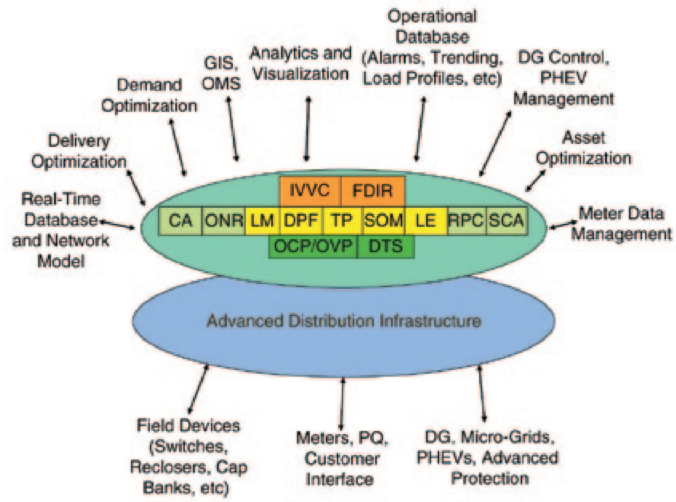

Figure 2.
Advanced distribution management for the smart grid.

- FDIR will require a higher level of optimization and will need to include optimization for closed-loop, parallel circuit, and radial configurations. Multi-level feeder reconfiguration, multi-objective restoration strategies, and forward-looking network loading validation will be additional features with FDIR.

- IVVC will include operational and asset improvements-such as identifying failed capacitor banks and tracking capacitor bank, tap changer, and regulator operation to provide sufficient statistics for opportunities to optimize capacitor bank and regulator placement in the network. Regional IVVC objectives may include operational or cost-based optimization.

- LM/LE will be significantly changed where customer consumption behaviors are no longer predictable but more smartly managed individually and affected by distribution response management.

- TP, DPF, ONR, CA, SCA, and RPC will be used on a more frequent basis. They will need to include single-phase and three-phase models and analysis, and they will have to be extended down the network to individual customers. Distributed generation, microgrids, and customer generation (such as plug-in hybrid electric vehicles (PHEVs) will add many challenges to the protection, operation, and maintenance of the distribution network. Small generation loads at the customer interface will complicate power flow analysis, contingency analysis, and emergency control of the network. Protection and control schemes will need to account for bi-directional power flow and multiple fault sources. Protection settings and fault restoration algorithms may need to be dynamically changed to accommodate changes in the network configuration and supply sources.

- Databases and data exchange will need to facilitate the integration of both geographical and network databases in an advanced DMS. The geographical and network models will need to provide a single-phase and three-phase representation to support the advanced applications. Ideally, any changes to the geographical data (from network changes in the field) will automatically update the network models in the database and user interface diagrams. More work is required in the areas of distributed real-time databases, high-speed data exchange, and data security. Take, for example, the interfaces and applications required to support roving PHEVs on the utility's (or another utility's) distribution network. Point-of-use metering and energy charge or credit must be managed and tracked on the distribution network. This is a challenge in terms of not only the additional load or potential supply (and related protection and control issues), but also the tracking and accounting of energy use or supply at various points on the distribution network or on a neighboring utility's distribution network. This will be a huge challenge for utilities and will lead to a significant change in data management and accounting—away from the once-a-month meter reading and billing of customers. The customer interface challenge is illustrated in Figure 3.

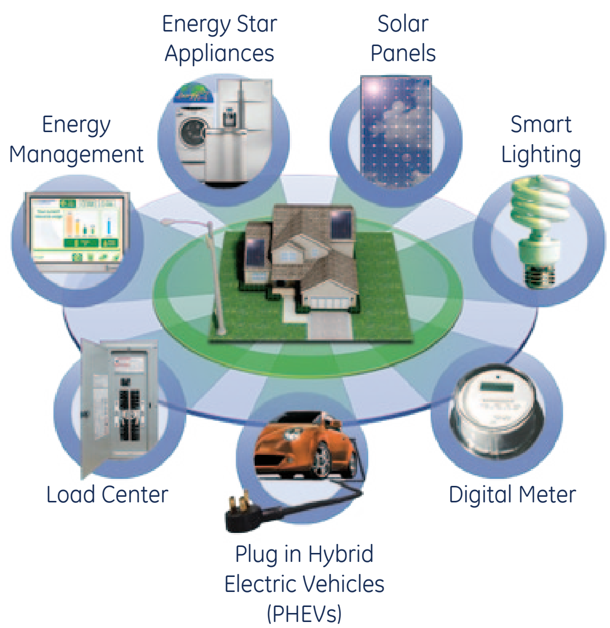

Figure 3.
The customer interface challenge.

- Dashboard metrics, reporting, and historical data will be essential tools for tracking performance of the distribution network and related smart grid initiatives. For example, advanced distribution management will need to measure and report the effectiveness of grid efficiency programs, such as var optimization or the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI), and other reliability indices related to delivery optimization smart grid technologies. Historical databases will also allow verification of the capability of the smart grid optimization and efficiency applications over time, and these databases will allow a more accurate estimation of the change in system conditions expected when the applications are called upon to operate. Alarm analysis, disturbance, event replay, and other power-quality metrics will add tremendous value to the utility and improve relationships with customers. Load forecasting and load management data will also help with network planning and the optimization of network operations.

- Analytics and visualization assimilate the tremendous increase in data from the field devices and integration with other applications, and they will necessitate advanced filtering and analysis tools. Visualization of the data provides a detailed but clear overview of the large amounts of data. Data filtering and visualization will help quickly analyze network conditions and improve the decision-making process. Visualization in an advanced DMS would help display accurate, near real-time information on network performance at each geospatially referenced point on a regional or systemwide basis. For example, analytics and visualization could show voltage magnitudes by color contours on the grid, monitor and alarm deviations from nominal voltage levels, or show line loading through a contour display with colors corresponding to line loading relative to capacity. System operators and enterprise users will greatly benefit from analytic and visualization tools in day-to-day operations and planning.

- Enterprise integration is an essential component of the smart grid architecture. To increase the value of an integrated smart grid solution, the advanced DMS will need to interface and share data with numerous other applications. For example, building on the benefits of an AMI with extensive communication coverage across the distribution system and obtaining operational data from the customer point of delivery (such as voltage, power factor, and loss of supply) helps to improve outage management and IVVC implementation.

- Enhanced security will be required for field communications, application interfaces, and user access. The advanced DMS will need to include data security servers to ensure secure communications with field devices and secure data exchange with other applications. The use of IP -based communication protocols will allow utilities to take advantage of commercially available and open-standard solutions for securing network and interface communications.

4. A New Way of Thinking

Smart grids are not really about doing things a lot differently than the way they are done today. Rather, they are about doing more of what we already do—sharing communication infrastructures, filling in product gaps, and leveraging existing technologies to a greater extent while driving a higher level of integration to realize the synergies across enterprise integration. A smart grid is not an off-the-shelf product or something you install and turn on the next day; it is an integrated solution of technologies driving incremental benefits in capital expenditures, operation and maintenance expenses, and customer and societal benefits. A well-thought-out smart grid initiative builds long-term focus. It is not a one-time solution but a change in how utilities look at a set of benefits across applications and remove the barrier created by silos of organizational thinking. While current smart grid initiatives are typically driven by regulatory pressure and tend to focus more on the meters as a direct impact on consumers, we are likely to see more technology-rich initiatives after well-proven smart grid evaluations ("staged deployments"). Expect to see traditional distribution management evolve to include advanced application the smart grid.

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Detection of Incipient Faults in Underground Medium Voltage Cables

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1. Introduction

Medium voltage underground cables may exhibit incipient, self-clearing arcing faults prior to failing permanently. These events typically last one half- cycle and extinguish at the first natural zero crossing of the current. The magnitude of the half-cycle event is primarily dependent on the location of the fault on the feeder, but is also dependent on the point on the voltage waveform that the fault starts.

Operational experience, at least in urban areas, suggests that it is beneficial to trip a feeder suspected of incipient cable faults automatically very early after detecting first symptoms of an incipient fault. Because it limits the overall energy at the point of fault, it also limits the often-repeated voltage transient seen by the system. However, the relatively short duration of an incipient fault and the inability to achieve selectivity via time coordination, make the design of an incipient fault protection function challenging. A simple instantaneous overcurrent element is not sufficient.

Along with presenting operational experience of these half-cycle events at a large urban utility, this paper details a simple and robust method for detecting incipient faults in cable and combined overhead and cable feeders. A number of security measures are implemented to make the method fast, secure and selective.

The method is based on current signals only (no voltage signal required) and, therefore, can be applied in simple feeder overcurrent relays. The logic is simple enough to be programmed via user-programmable math and logic available on some modern microprocessor-based relays.

Test results are presented and explained, including playback of field events and transient simulation using a digital power system simulator.

2. Operational Experience with Underground Cables

With the increased installation of system power quality monitoring devices at the substation level, it was noticed that prior to approximately 10 to 15% of feeder trips the feeder exhibited earlier signs of breakdown in the form of the half-cycle events described above.

Because the monitoring devices were at the substation level, typically installed on one of the supplying transformers, it was not known on which of the 8 to 30 feeders the disturbance was occurring. What was known was that anywhere from two cycles to two weeks later, these half-cycle events could manifest into a permanent multi-cycle fault, on the same phase, which would operate traditional overcurrent relay elements. The number of half-cycle events that occur before the "true" fault could be anywhere from one to more than 100.

Very rarely has a half-cycle event occurred in the medium voltage underground network system that has not resulted in a subsequent fault that could be linked to the earlier event by phase and also by magnitude of the neutral current.

The operating implications of these half-cycle faults are as follows:

Fault Energy and Safety

The resulting arc flash energy from these half-cycle events is typically 10 to 20% of a full 3- to 5-cycle fault. Limiting the energy released in a fault obviously has safety benefits for a crew that may be working in the vicinity of the feeder, and also limits the damage to other feeders or equipment. It also has benefits for transformer faults, in that it limits the possibility of a violent failure.

At one extreme, if the relay is enabled to trip after one half-cycle event, with no intentional delay, this would limit the energy of the full fault for almost all cases, except those where the half-cycle event precedes the eventual full fault by less than 3 to 5 cycles.

The other option is to have the relay alarm for these events, if the microprocessor relay is connected to an alarming scheme. This helps identify which feeder the fault is on, and the feeder may be taken out of service, or work in close proximity to the feeder restricted. Of course, this has limited value, because the full fault may occur before operational people can react to the alarm.

The decision as to whether to trip or alarm has the following considerations

- will it eventually fail permanently,
- what are the system conditions at the time of the fault,
- can the fault be located.

Ability to locate the fault is a major consideration in making the decision to allow tripping or just alarming.

Network Reliability

Every time there is a fault on the system, whether it is a full fault or a half-cycle fault, there can be some elevated voltage transients, particularly at the interruption of the fault. This is even more prevalent for ground faults on a large network system supplying delta-connected transformers from a station that is effectively ungrounded (typical source impedances for a Con Edison Area Station are Z1=0+0.2j ohms, Z0=0+0.95j ohms).

The problem that half-cycle faults present that are not present in "true" faults, where the feeder breaker opens, is that the half-cycle faults can be occur numerous times in quick succession. On a number of occasions they have been seen to occur multiple times at periods of less than 2 or 3 seconds apart. If, on occasion, a half-cycle fault occurred in a cable joint on a feeder about 40 to 50 times over 90-second period. At the end of the 90-second period, the fault manifested into a true fault, and tripped the breaker, but in the intervening 90 seconds, 2 other faults occurred on separate feeders, almost certainly caused by the voltage transients that occurred on the clearing of each half-cycle event. Within a 90-second period, the network went from all feeders in-service to a 3rd contingency, which was beyond the level designed for.

INCIPIENT FAULTS ARE LEADING INDICATORS OF DETERIORATING INSULATION - A TYPICAL FAILURE MECHANISM IS A PARTIAL DISCHARGE AND TREEING

Fault Location

There is another consideration regarding opening or tripping the feeder that has had these half-cycle faults: whether the fault can now be located using the fault locating techniques presently employed. The thinking being that because the fault self -healed at the first current zero, it will be less likely to break down again under elevated test voltage. This is certainly a consideration and to date there is very little data on this issue, as almost no feeders have ever been taken out of service for a half-cycle event.

However, there have been a few occasions where the fault has been a full-cycle self-clearing event, which operated the traditional relaying protection. Under these circumstances no particular difficulty was observed in locating the fault.

Although rare, another issue that has occurred is where the flash from a half-cycle event is observed by the public or by a crew. The knowledge that it is a primary half-cycle event, and not a low voltage secondary event, is garnered from a corresponding half-cycle disturbance recorded by the substation Power Quality (PQ) device. In this case, where the manhole structure contains only one primary feeder, the issue is simple. Take the feeder out, confirm the location of the fault, and repair. However, when there are multiple primary feeders in the hole, the issue is more complicated because, although the fault is localized to the structure, we may not know which feeder is having the problem, and entry to the manhole for a full inspection of the feeders is not possible for safety reasons. In these cases, having a feeder relay that trips or alarm for such events would be beneficial. In cases such as this that have occurred to date, the feeder with the half-cycle event has failed before any other actions were required. The eventual fault is correlated with the half-cycle fault by phase, approximate magnitude of neutral current, and the fact the half-cycle events cease.

3. Fundamentals of Incipient Faults in Cables

Incipient faults are leading indicators of deteriorating insulation. The aging process of the cable insulating material can be caused by a number of factors, including thermal, electrical, mechanical, and environmental/chemical factors. These mechanisms are relatively well understood. Reference [1] provides good background information. In [1] the aging factors for cables are classified as summarized in Table 1.

Most commonly, electrical stress is the predominant factor in causing cable failures. A typical failure mechanism is a partial discharge and treeing. The former mechanism takes place in organic dielectrics such as in the cross-linked polyethylene (XLPE) cables. The latter mechanism is typical in oil/paper-insulated cables and is aggravated by the presence of moisture.

Aging Factor		Aging Mechanism
Thermal	High temperature and temperature cycling	• Chemical reaction • Thermal expansion • Diffusion • Insulation melting • Anneal locked-in mechanical stresses
	Low temperature	• Cracking • Thermal contraction
Electrical	Voltage	• Partial discharges • Electrical trees • Water trees • Charge injection • Intrinsic breakdown • Dielectric losses and capacitance
	Current	• Overheating
Mechanical	Cyclic bending, vibration, fatigue, tensile, compressive and shear stress	• Yielding of materials • Cracking • Rupture
Environmental	Water, humidity, contamination, liquids, gases	• Electrical tracking • Water treeing • Corrosion • Dielectric losses and capacitance
	Radiation	• Accelerated chemical reactions

Table 1.
Cable aging [1]

This pre-breakdown phenomenon takes place in the form of either electrical trees or water tress [1]. The cause of treeing in dry dielectrics is partial discharges due to high electric stresses (Figure 1), and moisture at lower electric stresses (Figure 2).

Electrical Trees

The presence of high and divergent electric stresses is the primary contributing factor to initiate and propagate electrical trees [1]. An electrical tree may consist of many discharge paths including a "trunk" and "branches."

Electrical trees initiate at about 150kV/mm field strength. When initiated, an electrical tree will propagate through the insulation as a series of random bursts, and when the branches of the tree span the entire insulator layer, a breakdown occurs.

Water Trees

Water trees are caused in the presence of moisture typically at the semiconductor-insulation interface of a cable. Water trees typically start at lower electric fields and propagate slower compared with electric trees [1].

Water trees convert to electrical trees and result in a catastrophic failure. Typically the conversion is associated with a sustained discharge activity in cavities that are created in the water tree channels. Large water trees can convert at normal operating voltages, and small water trees convert at higher voltage levels during over-voltages caused by switching transients or lightning. As the discharge takes place in the water cavities, only water trees are not associated with detectable partial discharge patterns before converting to the electrical trees.

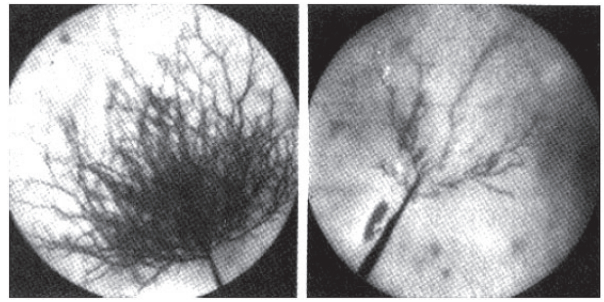

Figure 1.
Sample electrical trees [1]

Figure 2.
Sample water trees [1]

Incipient Faults

The process of converting a water tree into an electrical tree through a localized partial discharge is relatively complicated and can occur at various rates, including temporary regression of the degradation process due to evaporation of the moisture.

During such period of partial discharge high frequency components are present in the currents. The frequency spectrum spans into few or few tens of kHz, and the nature of such current spikes is random. This situation can last days or months or even years. This paper is not concerned with detecting incipient faults at this stage.

Eventually when the insulating layer is broken, a high fault current of a fundamental frequency is created. However, at this stage considerable damage is done to the cable, and the phenomenon will repeat at an accelerated rate leading very quickly to a permanent fault.

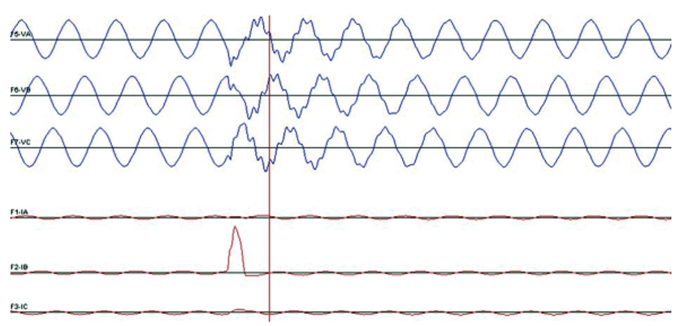

Figure 3.
Sample incipient fault: voltages (top) and currents (bottom)

Figure 3 shows an example of an incipient fault. The phase B current is affected showing a typical half-cycle fault pattern. When the current is self-extinguished considerable transients are created in voltages due to interactions between the cables inductances and capacitance.

4. Tripping of Incipient Faults in Cables

4.1 Fundamentals

This section describes a method for detecting incipient cable faults based on signals available to a feeder protective relay.

The algorithm is a heuristic pattern recognition function defining an incipient cable fault as the following event (compare with Figure 3):

- no load change occurs during an incipient fault; pre- and post-even currents are virtually identical, otherwise the event might be an external fault cleared very fast by a fuse;
- an incipient fault occurs in one phase only; the superimposed fault current in one of the phases matches, therefore, the neutral current;
- an incipient fault lasts for few multiples of a half cycle; a limit of 3 half-cycles is applied (vast majority of incipient faults are half-cycle events, and if lasting more than three half-cycle the incipient faults are detectable by traditional protection functions).

The above pattern is analyzed independently in each phase.

The algorithm described in this section processes samples of currents and half-cycle measurements to detect an incipient fault. This fine temporal resolution is necessary because of the short-lived nature of the incipient fault current. Processing filtered currents and their magnitudes estimated with full-cycle windows or longer would not be appropriate.

The basic algorithm detects a single incipient fault pattern based on the current. This is complemented by the following supplementary functionality:

- An overcurrent pickup setting is provided.
- A pickup operand is provided to flag a single occurrence of an incipient fault and can be used with counters and logic in customized user applications.
- Two hard-coded operating (tripping) modes are provided: trip on N-th count of the event (N is a setting) and, trip on the N-th count occurring in a time window T (both N and T are settings).

In theory more security can be brought into the algorithm by monitoring the voltage signal and specific patterns in it. This algorithm does not use voltages in order to expand its applicability to relays with no voltage measurements. The required security is ensured by monitoring certain features in the current signals.

Also, the algorithm is non-directional and will respond to a fault in either direction. This needs to be considered by operating the network in a loop configuration.

4.2 Algorithm

Signals and constants

i_A, i_B, i_C	instantaneous values of the current in phases A, B and C; in per unit of CT nominal; raw samples;
i_N	instantaneous values of the neutral current calculated from raw samples of currents in phases A, B and C;
i_{FA},i_{FB}, i_{FC}	fault components of the current in phases A, B and C calculated from raw samples of currents in phases A, B and C;
S_A, S_B, S_C	measures of match between the fault currents in phases A, B and C, and the neutral current;
I_{FA_MAG}	magnitude of the superimposed current in phase A (similar for B and C); estimated with the half-cycle Fourier;
I_{1MAG}	magnitude of the positive-sequence current;
Δ_{OC}	pickup level of the overcurrent detector in per unit of CT nominal (user setting);
N_1	number of samples per power cycle (64s/c);
N_M	length of the memory operation separating the fault and load components;
C_1-C_4	factory constants

Calculations

The neutral current is calculated first as:

$$i_{N(k)} = i_{A(k)} + i_{B(k)} + i_{C(k)} \quad (1)$$

In equation (1) and below, k stands for a sample index and means a present sample, while k – 1 means the previous sample, and so on.

Incremental (superimposed) current components are calculated next in order to separate the load and fault currents. This is done on samples using a 2-cycle memory:

$$i_{FA(k)} = i_{A(k)} - i_{A(k-N_M)} \quad (2a)$$

$$i_{FB(k)} = i_{B(k)} - i_{B(k-N_M)} \quad (2b)$$

$$i_{FC(k)} = i_{C(k)} - i_{C(k-N_M)} \quad (2c)$$

Under steady state conditions, even with distorted waveforms, the fault components are very small, ideally zero. During faults and other switching events, the above signals will reflect the fault component in the first two cycles of the fault.

During incipient faults the neutral current and the fault component in the affected phase match. Therefore a measure of that match is calculated as follows:

$$S_{A(k)} = \frac{2}{N_1} \cdot \sum_{j=0}^{\frac{N_1}{2}-1} \left| i_{FA(k-j)} - i_{N(k-j)} \right| \quad (3a)$$

$$S_{B(k)} = \frac{2}{N_1} \cdot \sum_{j=0}^{\frac{N_1}{2}-1} \left| i_{FB(k-j)} - i_{N(k-j)} \right| \quad (3b)$$

$$S_{C(k)} = \frac{2}{N_1} \cdot \sum_{j=0}^{\frac{N_1}{2}-1} \left| i_{FC(k-j)} - i_{N(k-j)} \right| \quad (3c)$$

Next, a half-cycle Fourier algorithm is run on the fault current samples:

$$i_{FA(k)} \rightarrow I_{FA\_MAG(p)} \tag{4a}$$

$$i_{FB(k)} \rightarrow I_{FB\_MAG(p)} \tag{4b}$$

$$i_{FC(k)} \rightarrow I_{FC\_MAG(p)} \tag{4c}$$

In equations (4) and below, p stands for a protection processing instant, while p – 1 means the previous processing instant, and so on.

It is assumed that the magnitude is scaled as the peak value.

Overcurrent conditions are declared based on the following flags:

$$OC_{A(p)} = \left(I_{FA\_MAG(p)} > \sqrt{2} \cdot \Delta_{OC}\right) \tag{5a}$$

$$OC_{B(p)} = \left(I_{FB\_MAG(p)} > \sqrt{2} \cdot \Delta_{OC}\right) \tag{5b}$$

$$OC_{C(p)} = \left(I_{FC\_MAG(p)} > \sqrt{2} \cdot \Delta_{OC}\right) \tag{5c}$$

A match between phase fault currents and the neutral current is established via the following flags:

$$R_{A(p)} = \left(S_{A(p)} < \max\left(C_1 \cdot I_{FA(p)}, C_2\right)\right) \tag{6a}$$

$$R_{B(p)} = \left(S_{B(p)} < \max\left(C_1 \cdot I_{FB(p)}, C_2\right)\right) \tag{6b}$$

$$R_{C(p)} = \left(S_{C(p)} < \max\left(C_1 \cdot I_{FC(p)}, C_2\right)\right) \tag{6c}$$

Next, the following flags are established:

$$E_{A(p)} = OC_{A(p\_)} \,\&\, R_{A(p)} \,\&\, not\left(OC_{B(p)} \text{ or } OC_{C(p)} \text{ or } R_{B(p)} \text{ or } R_{C(p)}\right) \tag{7a}$$

$$E_{B(p)} = OC_{B(p\_)} \,\&\, R_{B(p)} \,\&\, not\left(OC_{A(p)} \text{ or } OC_{C(p)} \text{ or } R_{A(p)} \text{ or } R_{C(p)}\right) \tag{7b}$$

$$E_{C(p)} = OC_{C(p\_)} \,\&\, R_{C(p)} \,\&\, not\left(OC_{A(p)} \text{ or } OC_{B(p)} \text{ or } R_{A(p)} \text{ or } R_{B(p)}\right) \tag{7c}$$

During incipient faults one of the above flags will pickup for a short period of time, depending on the magnitude of the current and duration of the fault.

The last step is to check the lack of loss of load in order to distinguish incipient faults from load changes or external faults.

Upon a rising edge of the E flag defined as:

$$E_{(p)} = E_{A(p)} \text{ or } E_{B(p)} \text{ or } E_{C(p)} \tag{8}$$

the following operations are performed:

- Magnitude of a pre-fault positive-sequence current is captured: . This value is a 2-cycle old value proceeding the rising edge of the E flag.
- Magnitude of the post-fault positive-sequence current is captured: . This value is a value that occurs 4 cycles after the rising edge of the E flag.

Consistent load is declared if the two values differ less than certain portion of the pre-fault current and the CT nominal current:

$$L = \left(\left|I_{1PRE} - I_{1POST}\right| < \max\left(C_3 \cdot \max\left(I_{1PRE}, I_{1POST}\right), C_4\right)\right) \tag{9}$$

The final event flags are supervised with the consistent load condition as follows:

$$Event_A = E_A \,\&\, L \,\&\, not\left(OC_{A(at\ post-fault)}\right) \tag{10a}$$

$$Event_B = E_B \,\&\, L \,\&\, not\left(OC_{B(at\ post-fault)}\right) \tag{10b}$$

$$Event_C = E_C \,\&\, L \,\&\, not\left(OC_{C(at\ post-fault)}\right) \tag{10c}$$

Figure 4 explains the timing relationship between the event flags and the pre- and post-fault currents.

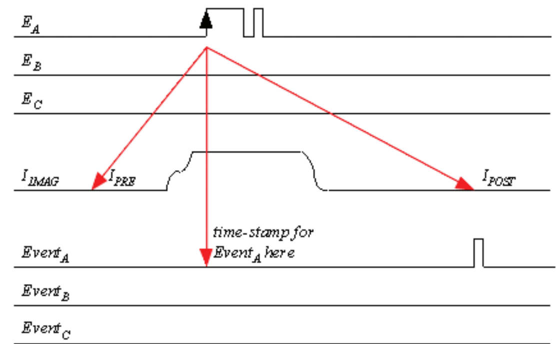

Figure 4.
Explanation of capture and application of the pre- and post-fault load check

4.3 Illustration of the algorithm operation

Figure 5 shows a case of an incipient phase-B fault registered by a feeder relay (top figure shows the raw A, B and C currents). The bottom portion shows the neutral current (blue) clearly revealing the fault period from under the load, and the superimposed phase B current (red). The superimposed current shows the fault current blip twice as the data slides through the 2-cycle memory window. During the actual fault, the neutral current and the superimposed phase B currents match very well, confirming the incipient fault hypothesis and identifying the affected phase.

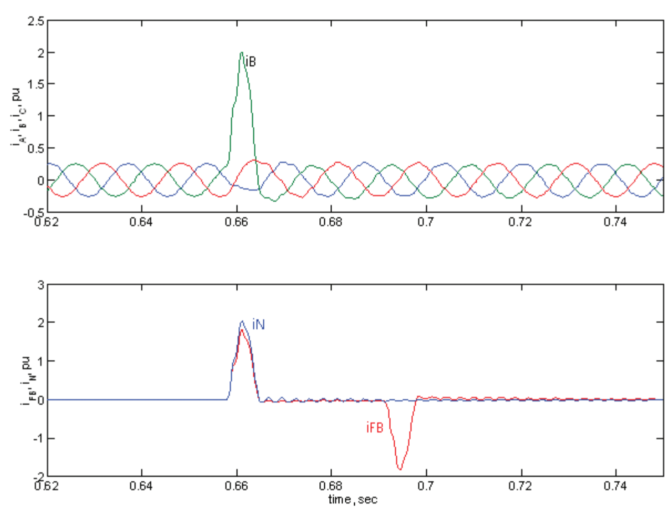

Figure 5.
Illustration of the algorithm: phase currents (top), calculated neutral and superimposed phase B current (bottom)

Figure 6 shows the magnitude of the superimposed currents. Due to half-cycle measurement, the fault current is estimated accurately (full cycle algorithm would see half of the current that last that short). The figure shows a user pickup threshold set at 0.5pu RMS. The bottom portion of the figure shows the S-values.

During the actual fault the B-phase value is low indicating a good match between the neutral and phase B current. During the mirror spike in the B-phase, the neutral and B-currents do not match, which will prevent misidentification of this event as a fault.

Figure 7 shows key logic flags of the algorithm. The neutral current is shown to signify the time of actual event. The E-flag is asserted shortly afterwards and stays robustly picked up. The OC-flags behave as expected: only the B-phase seen and overcurrent condition. Two pulses are visible: one for the actual event and the other for the mirror image due to the windowing effect. The match flags (R) are picked up during steady state conditions and reset during transients if the neutral and incremental phase currents do not match.

THE ALGORITHM IS A HEURISTIC PATTERN RECOGNITION FUNCTION DEFINING AN INCIPIENT FAULT AS A SERIES OF EVENTS

4.4 Testing recommendations

Simplified test waveforms for positive testing can be created by superimposing a three-phase balanced load current and an incipient fault current ("blip"). The fault current should be combined as a series of 1, 2, or 3 half-cycle waveforms (cosine shapes). The magnitude of the fault component can be varied to test the overcurrent pickup. Figure 9 below illustrates the idea.

Simplified test waveforms for negative testing shall include regular faults (both inception and removal), and other cases that violate definition of the incipient fault as stated in clause 4.1. This includes load pickup and dropout, open phase conditions (down conductor), single-phase load and phase unbalance, etc.

Figure 8 illustrates the measurement and capture of the positive-sequence current magnitude for the load consistency check.

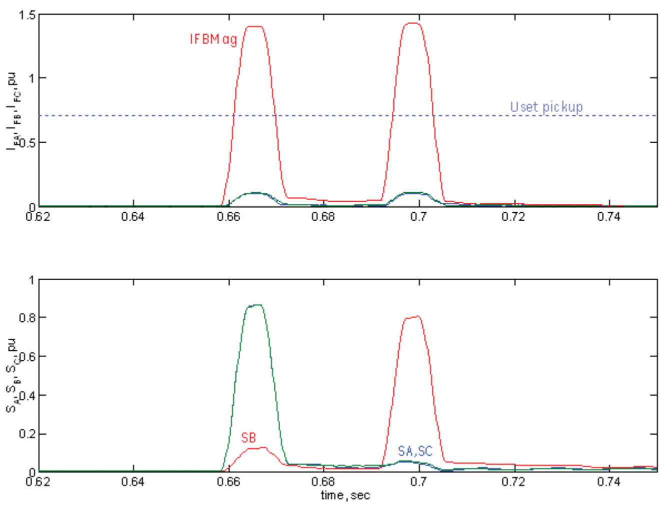

Figure 6.
Illustration of the algorithm: fault magnitudes (top) and S-values (bottom)

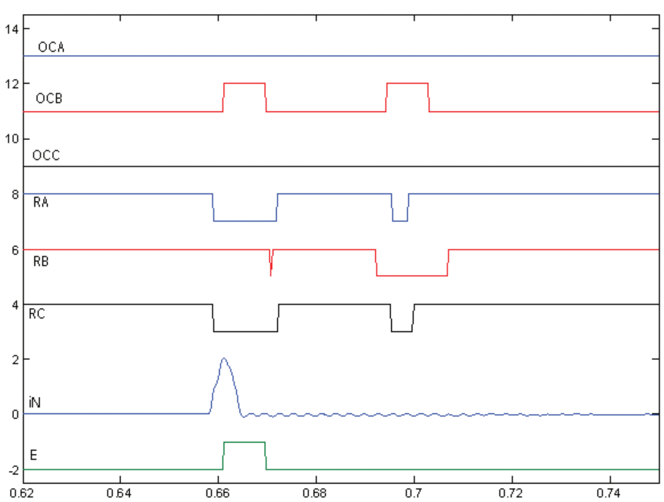

Figure 7.
Illustration of the algorithm: major logic flags

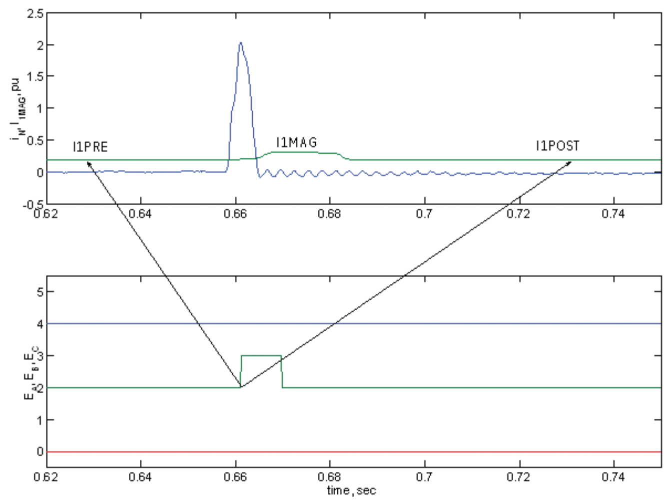

Figure 8.
Illustration of the algorithm: positive-sequence magnitude and the pre- and post-fault current points

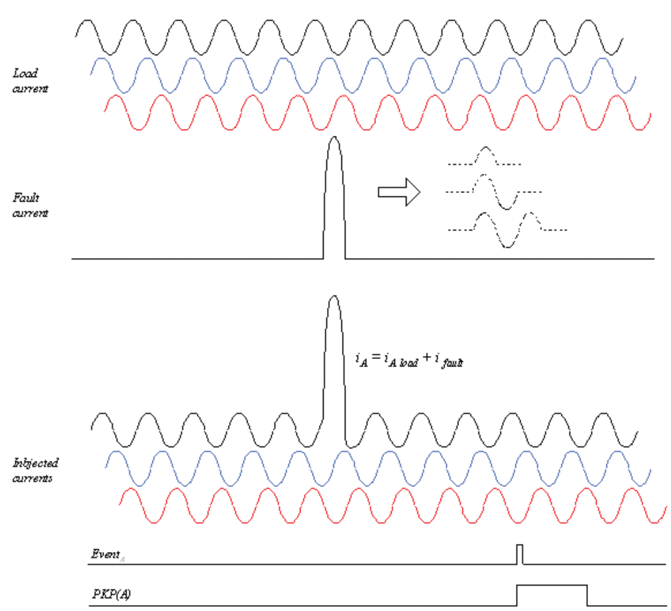

Figure 9.
Illustration of a simplified positive test of the algorithm

4.5 Operation using transformer currents

The method can be used with the total current supplied from the transformer toward the distribution bus. By subtracting the load current the method retains its sensitivity even though the load current may be significant as compared with the fault current. Of course, when supplied with the total current, the method loses selectivity and may be used for alarming rather than tripping.

The method cannot be directly applied to the high-side transformer currents. For a wye/delta transformer, it is not possible to reconstruct the zero-sequence current on the low-side wye winding from the high-side delta winding currents. Therefore, measuring the high-side delta currents a relay is not able to calculate the true values of the low-side phase currents. However, both the positive- and negative-sequence components on the low-side can be reproduced from the high-side currents, and an expanded method is possible to detect the short lasting incipient faults in the low-side from the currents captured on the high-side of the transformer.

5. Field and Test Examples

Figure 10 presents result of a playback of a sample incipient fault cases recorded by a feeder relay. The event is successfully detected after few cycles of delay in the algorithm provisioned for checking the load change.

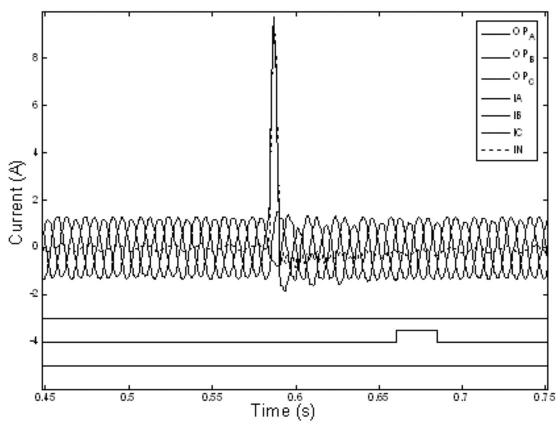

Figure 10.
Illustration of a simplified positive test of the algorithm

Figure 11 presents a sample test case from a real time digital simulator. The incipient fault function was set to operate on the second occurrence of the fault within a pre-defined time window. The element picks up on both incipient faults and operates, as configured, on the second instance. This application can be used to ride through a single incipient fault but operate if the trouble is progressing. The PKP operand may be used for alarming, and the OP operand – for tripping.

Figure 12 illustrates a case of an incipient fault with the magnitude of 3.1pu RMS and duration of one full cycle. The phase IOC function is set at 3.0pu, the neutral IOC function is set at 1.5pu, and the negative-sequence IOC is set at 0.5pu. All three elements are used as instantaneous. Depending on the magnitude of the incipient cable fault, it may or may not be detected by conventional protection elements. In this case, the neutral IOC function operates in addition to the dedicated incipient fault detection function.

For comparison, Figure 13 shows a case of a fault lasting two cycles. This fault is seen by traditional protection but not by the dedicated incipient fault element. The latter does not respond by design as the event lasts longer than three half-cycles and is very unlikely to be an incipient fault.

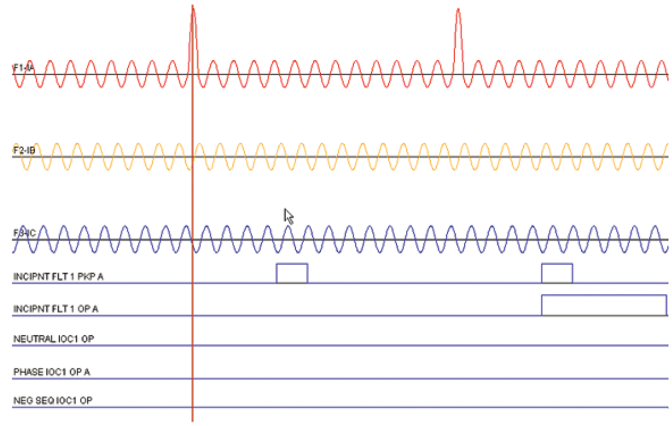

Figure 11.
Operation example of the incipient fault element configured to trip in the second incipient fault

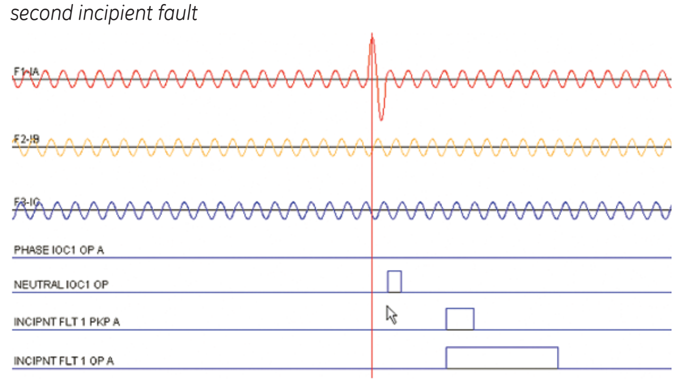

Figure 12.
Example of a one-cycle incipient fault detected by the incipient fault function and some traditional short circuit protection functions

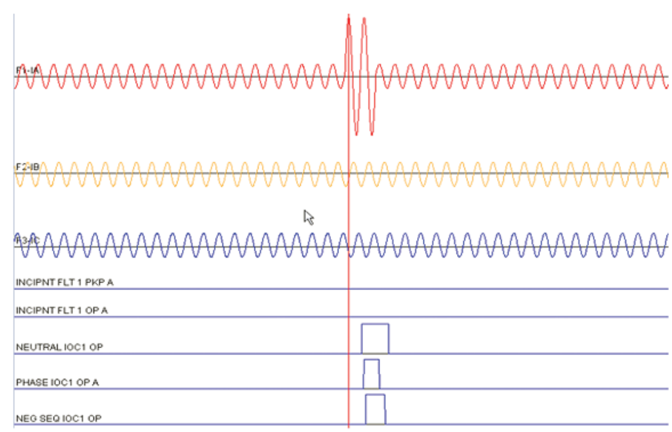

Figure 13.
Example of a two-cycle fault detected by the traditional short circuit protection functions, and not signaled (correctly) by the incipient fault detector

When testing the incipient fault function it is recommended to apply cases of traditional (permanent) faults, unequal pole closing/opening, external ground faults including very fast clearing via fuses, capacitor bank switching, transformer energization and similar events that may cases patterns of elevated current lasting between half a cycle and few cycles.

6. Application Guidelines for Tripping Incipient Cable Faults

The issues that come into the decision to deploy the logic in the first place is how often does the phenomena occur before each genuine fault. As discussed previously, it is estimated that approximately 10% to 15% of faults on the underground system that operate traditional relaying are preceded by at least one half-cycle event.

So, even with full deployment of this system, there will be no impact on the arc flash energy for 85 to 90% of all faults. That being said, there is some evidence to suggest that the number of half-cycle events is on the increase and this may be because they are more prevalent in the newer mechanical type joints that are making up an increasing percentage of the system.

Having decided to implement the logic, the decision really comes down to whether to alarm or to trip. If deciding to trip, the decision comes down to whether to trip after the detection of the first half-cycle event or whether to wait until two or three events occur (possibly even in a certain time period). What influences this decision is the number of events that are typically seen before the full fault and the time difference between the first event and the final fault.

The first issue to consider is that on a fully underground system, where there are no downstream HV switching devices (breakers, fuses) to co-ordinate with, if a half-cycle event has occurred, then the cable will almost certainly fail leading to a fault that will operate traditional overcurrent elements.

The problem faced by the relay engineer is really one caused by the fact he now has a choice as to whether to trip the breaker or wait until the full fault.

Ideally, if one has communication with the relay then one might be more inclined trip at periods of low load or low system risk, and more inclined to see if the feeder will hold in during a summer heat wave. However, if the half-cycle event becomes more frequent with subsequent over-voltages produced by the events, the best thing for reliability purposes (to prevent damage to components on other feeders) may be to take the feeder out of service irrespective of loading and system conditions.

It needs to be recognized that the algorithm may trigger on an external fault on a unloaded or lightly loaded branch cleared fast by a fuse. Also, arrester operations may appear as half-cycle events and potentially trigger the algorithm. These must be taken into account when deploying the technology or troubleshooting field cases.

A METHOD HAS BEEN PRESENTED TO DETECT INCIPIENT FAULTS IN A SECURE AND RELIABLE WAY

7. Summary

This paper presents an operational experience with incipient faults: it has been observed that 10 to 15% of cable faults are preceded by incipient faults. Practically, all incipient faults become permanent faults in the period between a few seconds to few weeks. Incipient faults occurring in fast successions create considerable over-voltages and induce faults on other feeders.

A method has been presented to detect incipient faults in a secure and reliable way. The method is secure by checking consistency of the load before and after the event, checking if the event is a single phase event, and checking for duration and consistency between the superimposed fault component and the ground current.

The presented method has been implemented [2] and tested using recorded field cases and on a digital simulator. Simplified variants of the method can be implemented by using programmability and flexibility of modern microprocessor based relays.

Recommendations are given as to the trip vs alarm applications of the incipient cable fault detection functions. In many cases tripping on the first incipient fault is a prudent application.

8. References

[1] N.H.Malik, A.A.Al-Arainy, M.I.Qureshi, Electrical Insulation in Power Systems, Marcel Dekker, 1998.

[2] F60 Feeder Management Relay, Instruction Manual, General Electric. Available at www.multilin.com.

Justifying Distribution Automation

Randy Kimura, Byron Flynn
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1. Introduction

If the Smart Grid is the noun on everyone's lips today, DA (Distribution Automation) is the verb that empowers the Smart Grid to become really smart. In its broader context, DA provides for the quick restoration of power to the customers, through remote control and the automatic reconfiguration of feeders [1]. The appropriate level of DA can be difficult to determine; furthermore, the diversity of a utility's service territory can make a single DA solution inappropriate. It becomes important to understand the costs and performance metric improvements that each of these levels brings to a typical feeder.

This paper discusses the models developed to calculate improvements in customer outage minutes for various levels of DA. The model adapts for the number of customer in each segment, the likeliness of a fault occurring in each segment and the availability of an alternate source. The modeling and outage duration analysis is based on the typical feeder layout shown in Figure 1.

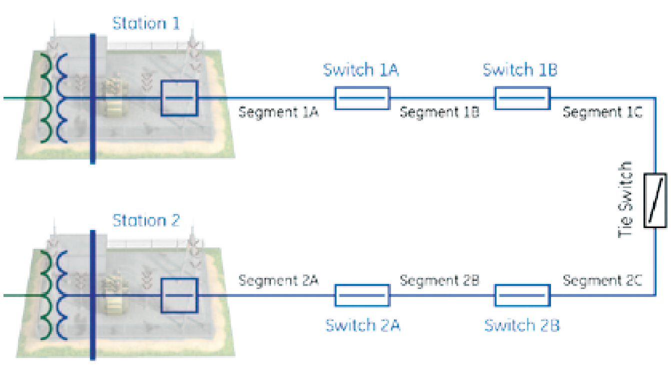

Figure 1.
Feeder Used in Studies

Two feeders are shown connected by a tie switch allowing the potential for unfaulted segments of a circuit to be restored from an alternate source. The analysis model was designed with an input variable that can account for times that the alternate source was unavailable due to capacity constraints or simply is not physically available. This allows the comparison of circuits with no alternate source tie or when the alternate source can only be used occasionally. The substation feeder breaker is assumed to have SCADA communications in both substations. This provides station breaker trip and lockout indication and feeder breaker control to dispatch.

The analysis includes the expected reliability index improvements under various levels of DA deployment and the expected costs and benefits of automation and communications for those levels.

2. Outage Duration Modelling

The model is adaptable, supporting a range of parameters associated with the restoration of service. Variables used to represent the feeder include:

- Fault Likeliness – The likeliness of a fault occurring on a feeder segment.
- Customers – The number of customers serviced by a feeder segment.
- Simple Travel Time – Average travel and response time to arrive in the area and begin inspecting for trouble.
- Simple Repair Time – Average time for a simple repair (a fault without damage), for example tree limb related fault.
- Complex travel Time – Average travel and response time for a crew to arrive in the area and begin repairing the line.
- Complex Repair Time – Average time for a complex repair (a fault with damage), for example a downed pole or conductor.
- % Complex Faults – Percentage of faults requiring the longer repair time.
- Faults/Year – Average number of faults per year on the feeder that require a response.

The second generation of this tool uses separate simple and complex repair and travel times. This influences the model for the different personnel required for each type of repair. The response time for a simple repair, typically addressed by a single trouble-shooter, is less then a complex repair that is typically addressed by a crew.

Each of the cases was analyzed to determine the typical steps and times to restore all the customers on the circuit. Care was taken to use estimated durations that represented realistic amounts. This proved to be a significant challenge because there are so many differences in variables like feeder topology, geography fault types, and dispatcher or crew response times. The model analyzed each segment of feeder for two types of faults, simple and complex.

2.1 Assumptions

The model variables are designed to accept values representative of a utilities feeder. This paper will use the same default values to evaluate each DA level thereby providing consistency and allowing for the accurate comparison of DA levels.

- The likeliness of a fault occurring is set to 33% for each segment.
- The number of customers serviced is set to 600 for each segment.
- The simple travel time is 20 minutes and the repair time is 30 minutes.
- The complex travel time is 45 minutes and the repair time is 2.25 hours.

2.2 Benchmarking

Manual disconnects are modeled and used as a benchmark to evaluate the merits of subsequent levels of DA. Simple and complex faults are modeled with and without an alternate source. The following table lists the steps to address a segment 1A simple fault without an alternate source.

Avg. Time	% Out	Fault Mins	Step
0:01	100%	0:01	Fault occurs
0:05	100%	0:05	Dispatcher contacts trouble-shooter
0:20	100%	0:25	Trouble-shooter travel time
0:30	100%	0:55	Trouble-shooter repair time
0:05	100%	1:00	Dispatcher closes feeder A
	0%	1:00	Service restored

Table 1.
Seg. 1A Simple Fault

Table 2 includes the steps taken for a segment 1A simple fault with an alternate source.

Avg. Time	% Out	Fault Mins	Step
0:01	100%	0:01	Fault occurs
0:05	100%	0:05	Dispatcher contacts trouble-shooter
0:20	100%	0:25	Trouble-shooter travel time
0:30	100%	0:55	Trouble-shooter repair time
0:05	100%	1:00	Dispatcher closes feeder A
	0%	1:00	Service restored

Table 2.
Seg. 1A Simple Fault with Alternate Source

The steps taken for a segment 1A complex fault without an alternate source is listed in Table 3. A trouble-shooter performs the initial investigation, determines it is a complex fault and notifies the Dispatcher who contacts the repair crew.

Avg. Time	% Out	Fault Mins	Step
0:01	100%	0:01	Fault occurs
0:05	100%	0:05	Dispatcher contacts trouble-shooter
0:20	100%	0:25	Trouble-shooter travel time
0:05	100%	0:30	Dispatcher contacts crew
0:05	100%	1:00	Dispatcher closes feeder A
0:45	100%	1:!5	Crew travel time
2:15	100%	3:30	Crew repair time
0:05	100%	3:35	Dispatcher closes feeder A
	0%	3:35	Service restored

Table 3.
Seg. 1A Complex Fault

Table 4 includes the steps taken for a segment 1A complex fault with an alternate source. The trouble-shooter manually restores service by transferring unfaulted segments to the alternate source. This manual restoration occurs while the repair crew is travelling resulting in a decrease in customer minutes interrupted prior to the crew starting the repair.

Avg. Time	% Out	Fault Mins	Step
0:01	100%	0:01	Fault occurs
0:05	100%	0:05	Dispatcher contacts trouble-shooter
0:20	100%	0:25	Trouble-shooter travel time
0:05	100%	0:30	Dispatcher contacts crew
0:15	100%	0:45	Trouble-shooter opens Sw 1A.
0:15	100%	1:00	Trouble-shooter closes Tie Sw
0:45	33%	1:05	Crew travel time (concurrent with Sw 1A and Tie operation)
2:15	33%	1:50	Crew repair time
0:05	33%	1:51	Dispatcher closes feeder A
	0%	1:51	Service restored

Table 4.
Seg. 1A Partial Restoration of Damage Fault

3. Case Studies

Each level contains a different amount of automation and varying levels of remote communications. The cases presented in this paper represent a subset of the scenarios supported by the modeling tool. Additional cases that have been analyzed include:

- Automatic circuit reclosers
- Automatic circuit reclosers with remote control
- Closed loop automation with the tie switch normally closed

3.1 Automatic Circuit Reclosers

This scenario is shown in Figure 2 and replaces the manual disconnect switches with Automatic Circuit Reclosers (ACR). This level of automation allows several automatic isolation points to reduce the outage minutes for customers on segment 1A or 1B for faults further down the feeder in segment 1B or 1C.

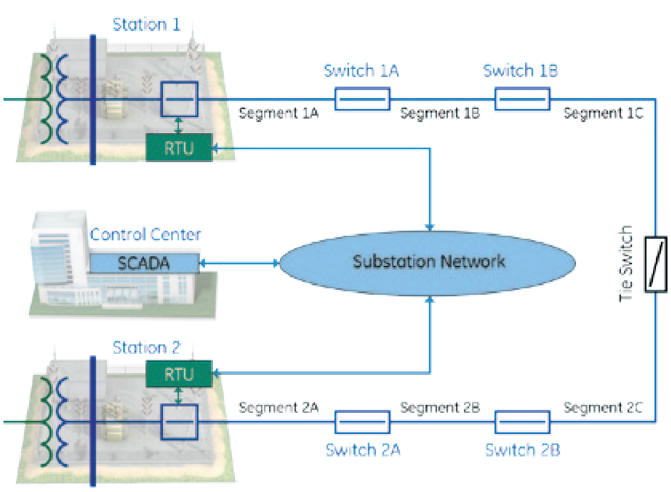

Figure 2.
Manual ACR

3.2 Automatic Circuit Reclosers with Remote Control

This case adds remote communications to the reclosers and tie switch along the feeder. This case allows remote control of the feeder breakers and switches. The Dispatcher can remotely isolate the fault and manually restore unfaulted segments from an available source.

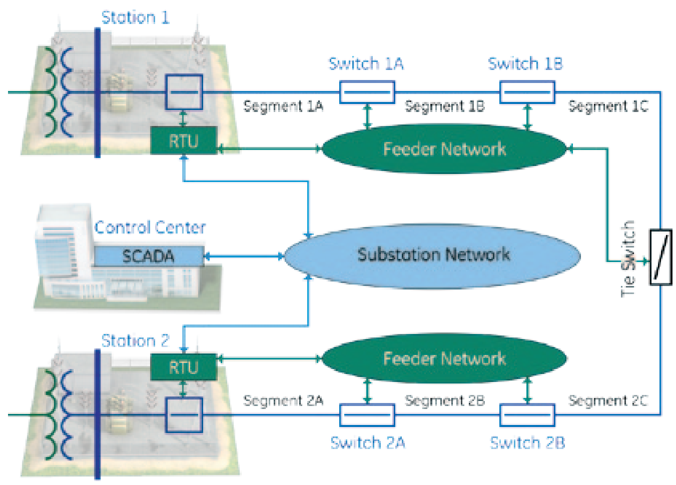

Figure 3.
ACR with Remote Control

3.3 Fault Detect Isolate Restore

The FDIR software will, depending on the appropriate safety and operational procedure checks, automatically isolate faults along the feeder between the switches and restore unfaulted segments as alternate sources are available. For example, faults in Segment 1B will not be noticed by customers in Segment 1A. Customers in Segment 1C will automatically be isolated from the fault and be restored depending on availability of the load in that segment to be restored from Station 2.

3.4 Summary

Table 5 lists the outage minutes for each customer experienced over a year. The calculation is based on the default values stated in the assumptions. The results are as expected, the CMI decreases as the amount of automation and communications increases.

Case	CMI
Manual Disconnects	156
Automatic Circuit Reclosers	149
Automatic Circuit Reclosers with Remote Control	109
Fault Detect Isolate Restore	93

Table 5.
Outage Minutes/Customer

4. Analysis

The total net costs for each case was calculated to be used in the final cost/performance comparison. While there are several financial models that could be used to capture the net total costs for each case, it was determined that a simple net present value (NPV) model would be used since it was simple and it matched the mathematical significance of the assumptions made elsewhere in the analysis. The initial model primarily focuses on Capital, the second generation also includes a prevent value representation of the potential changes to the skills and personnel needed for Engineering Design, Construction, and Field Support.

Case	Cost
Manual Disconnects	$13,750
Automatic Circuit Reclosers	$125,000
Automatic Circuit Reclosers with Remote Control	$169,666
Fault Detect Isolate Restore	$252,413

Table 6.
Costs per Feeder

The information from Table 5 can be used to calculate the incremental improvements between the various cases and the base case. The second column in Table 7 details the improvement, against the base case, to customer minutes interrupted for a feeder with 1800 customers.

Case	CMI Gain	Cost/CMI
Manual Disconnects	Base	Base
Automatic Circuit Reclosers	11,520	$10.85
Automatic Circuit Reclosers with Remote Control	84,000	$2.01
Fault Detect Isolate Restore	113,340	$2.23

Table 7.
Comparison to Base Case

From the data the worst performing case is Automatic Circuit Reclosers. Automatic Circuit Reclosers with Remote Control and Fault Detect Isolate Restore have similar benefits however the cost of Fault Detect Isolate Restore is 50% more then Automatic Circuit Reclosers with Remote Control.

Dispatcher availability significantly influences the automation and remote communications results. The analysis described in Table 7 is for a readily available dispatcher who can respond in 5 minutes. Table 8 describes the benefits when the dispatcher is busy, for example during a storm, and requires 15 minutes to respond.

Case	CMI Gain	Cost/CMI
Manual Disconnects	Base	Base
Automatic Circuit Reclosers	18,870	$6.62
Automatic Circuit Reclosers with Remote Control	100,320	$1.69
Fault Detect Isolate Restore	152,130	$1.66

Table 7.
Busy Dispatcher Comparison

There is an improvement, for each studied case, in the Customer Minutes Interrupted gain versus the base case when the dispatcher is busy. The largest increase occurs for Fault Detect Isolate Restore where the system restores as much service as possible without any instruction from the dispatcher.

An analysis to determine the number of feeders to be recommended for automation must be conducted based on the historical per circuit outage times. One utilities 2007 study is

THE INCREASING LEVEL OF DA IMPROVES RELIABILITY BY DECREASING THE CUSTOMER OUTAGE MINUTES

shown in Figure 4. From the data, it was determined that approximately 70% of the area under the curve is accounted for in the highest 200 feeders, as shown by the vertical line at 200 on the graph. This formed the basis of the recommended level of automation.

This tool and the subsequent analysis have been applied when the incentive is limited to avoiding the penalty band. The feeder automation decision point may be different for a reward and penalty band based incentive. These performance-based incentives are designed to either reward a utility for over performance or penalize them for underperformance [2].

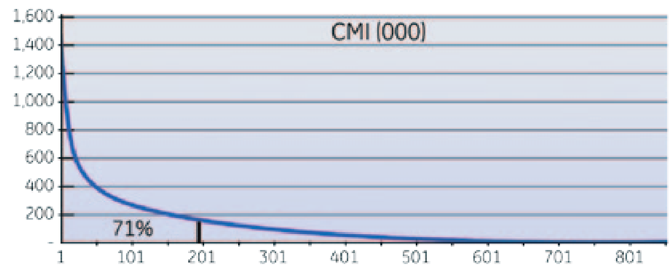

Figure 4.
Customer Minutes Interrupted by Circuit

5. Conclusion

Raising the capital expenditure increases the amount of automation and remote communication deployed. The increasing level of DA improves reliability by decreasing the customer outage minutes. Modeling and subsequent analysis has revealed that the improvements from a modest investment may not be the optimal solution. The capital expenditure per CMI gained is an important metric. An additional investment many produce significant improvements in reliability.

8. References

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Replenishing the Aging Work Force in the Power Industry

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Abstract

This paper discusses the program to develop, and more importantly, to attract the interest of the next generation of technical experts. The respective roles of industry and academia are discussed. Replenishing the aging work force is discussed as a four step approach starting with increasing the size of the available work force supply pool by presenting the profession as an appealing career choice. Encourage and support career entry by making the process a seamless transition into the power industry. Effectiveness of the new work force is accelerated through fast tracked training and development. Strong retention programs reduce departures from the industry.

1. Introduction

Aging work force, especially in the power industry, is a frequently discussed topic at the forefront of many organizations's management planning. From human resources to engineering, the power industry has known for years that the current trend will eventually result in a shortage of qualified personnel required to maintain and support the well being of the business. If there is no corrective action to reverse this trend, then who will keep the lights on? Today's recruiting and retention must replace outgoing personnel, but, more importantly, it must bring new blood into the power industry.

In general, resource development is the responsibility of industry and academia; using a joint and/or independent approach. Academic institutions provide the initial instruction for students. Industry focused instruction is provided to new graduates by their employers. In addition to a summer student program, the introduction of internship and co-op programs brings academia and industry together; exposing students to specific industries prior to graduation.

The power industry needs to be very visible as a valuable, meaningful, and long-term career choice - to both students and new graduates. Technical training and career development for new recruits should be recognized as an effective investment in the work force supply. Within the power industry, appropriate business plans/models are necessary for identifying the work force requirement. Based on the work force requirement, succession planning (for the business) and professional advancement (for employees) need to complement each other. This approach, when applied diligently, will replenish the aging work force and keep the lights on.

2. Increase the Size of the Work Force Supply Pool

The existing work force in power industry is aging faster and faster, and the available size of experienced resource pool is getting smaller and smaller. Nowadays, typical demographic in a power utility shows mainly two major groups. One group is the well-seasoned veterans (or old-timers), and the other is the eager rookies (or new-comers). There are not many in between the two groups. In order to ensure constant and adequate work force resources, the power industry needs to look closely at the work force supply and demand situation.

ONE GROUP IS THE WELL-SEASONED VETERANS (OR OLD-TIMERS), AND THE OTHER IS THE EAGER ROOKIES (OR NEW-COMERS)

2.1 Identify the Root Cause

During the early nineteen nineties, many power industry companies were downsized, re-organized and re-engineered. Especially in the power utility business, work force reduction was top priority with various early retirement incentives and hiring freezes across the whole organization. Employment opportunities were very limited, even for the highly educated, new graduates from Power Engineering Departments of well-known universities. Because of this negative employment impact, enrollment in Power Engineering in many universities became lower and lower, over the years. With low enrollment, various universities reduced the teaching faculties in Power Engineering. In fact, some universities stopped offering Power Engineering courses because of extremely small class size. When course offerings were not readily available, fewer and fewer students were able to take any Power Engineering courses. Since employment opportunities in the power industry became scarce, fewer and fewer students were interested in Power Engineering. With this vicious circle, many universities could not adequately support the Power Engineering program, in terms of faculty size or teaching resources. On top of that, the boom of "Dot Com" activities and the popularity of Information Technology (IT) enterprises in the nineties created a sizeable drain from the limited available resources for Power Engineering towards the supply pool for Computer & Software Engineering. This was clearly demonstrated by the increase in student enrollment and financial grants in Computer & Software Engineering, with an almost equal decrease in student interest, course availability and financial support in Power Engineering. This unfortunate situation is the root cause of the problem, which resulted in a big void in the supply side of Power Engineering graduates, especially in the late 2000s when the power industry needs to replenish the aging work force.

2.2 Collaboration Between Industry and Academia

In order to rebuild and strengthen the supply side of Power Engineering graduates, power industry and academia must recognize the fact that they need each other to be successful. Then, mutual collaboration is the essential strategy for all parties involved. With that in mind, the power industry needs to support academic institutions with financial contribution, curriculum review and suggestions, power industry insight and career opportunity outlooks. In return, academic institutions need to revitalize the Power Engineering program, increase the size of Power Engineering teaching faculty, align with the power industry work force requirement and projection, offer more Power Engineering courses and produce more well-educated Power Engineering graduates.

Similar to situations elsewhere, including especially North America, power industry in Alberta, Canada encountered the same problem of short supply in Power Engineering graduates from academic institutions within the province. To rectify this supply side problem, several key players in the Alberta power industry joined force with a provincial university in 2007 to form the Alberta Power Industry Consortium (APIC). This non-profit organization, namely APIC, represents an excellent example for "collaboration between industry and academia" for the ultimate good of society and citizens of the country.

APIC's mission statement states that: "Bring Alberta power companies together, with University of Alberta as the coordinating organization, to solve technical problems of common interest, to produce more well-educated graduates, to support professional development of current employees, and to promote cooperation and exchange in Alberta power engineering community." As indicated by this mission statement, in addition to increasing the "work force supply pool" by producing more graduates, there are many other tangible benefits to all participants of the consortium.

Within APIC, There are six core members and two supporting organizations.

The six core members are:

- Alberta Electric System Operator - Utility Regulator
- AltaLink Management Ltd - Transmission Utility
- ATCO Electric - Transmission & Distribution Utility
- EPCOR - Transmission & Distribution Utility
- Fortis Alberta - Distribution Utility
- University of Alberta - Academic Institution

The two supporting organizations are:

- iCORE (Informatics Circle Of Research Excellence) - Alberta's provincial government research agency.
- NSERC (Natural Science and Engineering Research Council of Canada) - Canada's federal government research agency

In terms of financial input to the consortium, each core member committed a multiple-year contribution of financial grant, with the exception of University of Alberta. The total financial grant from the consortium members was then matched by a provincial grant from the provincial government (i.e. iCORE). Furthermore, the total financial grant including the provincial contribution was then matched once again by a federal grant from the federal government (i.e. NSERC). Management and usage of these financial grants become the accountability of the consortium, especially in the case of University of Alberta acting as the coordinating organization.

In the spring of 2008, an Industrial Research Chair in Power Quality has been appointed at University of Alberta as a result of APIC's initiatives. Based upon the funding allotted to this research chair, new and additional faculty members will be hired in the discipline of Power Engineering. With this new infusion of teaching faculty bench-strength, more Power Engineering courses are planned and will be offered to target and attract new students. Higher enrollment in Power Engineering studies will produce more Power Engineering graduates. Therefore, this particular strategic move is expected to increase the size of the power industry work force supply pool.

For the purpose of alignment with real-life requirements and future outlooks of power industry, the existing Power Engineering curriculum was reviewed by APIC. Constructive recommendations were accepted by University of Alberta to enhance course development in Power Engineering.

Besides the increase in size of work force supply, other tangible benefits generated by APIC are as follows:

1. Solve technical problems through collaborative research

- Completion and delivery of projects with common interest to APIC members
- Work with project collaborators from the power industry
- Coordinate joint projects from various APIC members
- Assistance in technology and human resources transfer

2. Support professional development

- Six continuing education courses in the next five years
- Four research project based courses on specific subjects
- Project reporting and technology transfer

3. Promote industry-wide cooperation

- Jointed efforts in project research & collaboration
- Holding annual conference/forum
- Participation in workshops and seminars organized by APIC

Since the formation of APIC in 2007, the feedback from consortium members were very positive. There were many valuable and visible achievements. One good example was the First Annual Power & Energy Innovation Forum held in November 2008. During this one-day forum, technical staff from each consortium member did a presentation to highlight interesting projects or activities in their organizations. The objectives were to promote technical innovation, to exchange knowledge and ideas; and to share real-life experience and learning. The technical topics presented were as follows:

- Development in Wind Power Integration in Alberta
- Dynamic Thermal Line Rating (DTLR)
- IEC® 61850 Substation Automation
- Remote Fault Indication for Distribution Systems
- Advanced Metering Infrastructure (AMI) Program
- Flexible AC Signaling (FACS) Technology

3. Encourage & Support Career Entry

Recruiting and staffing must evolve and adapt to the business and economic climate. In many instances, the traditional approach of recruiting from graduating classes is insufficient. Collaboration programs provide employers an early start in the recruiting process. It also helps potential employees (students) to start career planning and development prior to graduation.

3.1 Student Programs

The future of today's companies lies in the hands of the students who are completing their degrees. In a few years, these students will be entering the job market as full-time employees; their potential bounded only by their imagination. In an effort to engage and challenge the minds of these students, while opening their eyes to the possibilities of what the future can hold, work experience terms not only involves the students in the everyday workings of the business, but challenges them to develop innovative and imaginative solutions to complex problems. Through these programs, employers can open the imagination of the students to the possibilities of life after school.

The academic phase of a career focuses on developing core knowledge and skills, which is often biased towards the theoretical. The working phase of a career then applies this knowledge and skill to industry specific applications, bridging the gap between theoretical and real-life. It is advantageous for both an employee and employer to have these two career phases overlap thereby permitting the real-life application of academic studies as early as possible. Work-term experience programs provide this opportunity, allowing students to put what they have learned into practice. In addition, these work-term experience programs also provide an introduction into an industry sector. Employers can promote the power industry, and more importantly, the wide range of career paths available within the industry.

1. Summer Students

Summer students are employed for the shortest period, 4 months, which limits the scope of learning and experience. A summer student's training is typically limited in scope, focusing on a specific topic. Summer employment provides students an entry point into an industry before they qualify for a co-op or internship program. Hiring summer students allows employers to evaluate future talent, which can be encouraged into co-op programs, internships and permanent employment.

2. Co-op Students

Co-op students are available for 4 or 8 months with the longer 8-month term being preferred. The longer period allows for more diverse training than can be provided for summer students, and can include additional topics or span across multiple departments (cross functional training). The longer duration also allows for longer duration tasks, in many cases, small projects can be executed by a co-op student.

3. Interns

The long duration of an internship, typically 12 to 16 continuous months, allows for the most investment in a student. Internships are preferred over co-op and summer students because it most closely resembles full time employment. Interns participate in personal career planning programs managed by Human Resources. Experiencing a "Performance Review" or "Goals and Objectives" session teaches an intern about career management.

Interns follow the same development process as first year technical staff, and all technical training is required. Even though an intern may remain in an office setting, the training required for field services personnel will also be assigned. Environmental Health and Safety courses, such as "Lock Out Tag Out" and "Confined Spaces," allow an intern to appreciate the activities that occur outside of the office place.

The local engineering governing body, the Association of Professional Engineers, Geologists, and Geophysicists of Alberta (APEGGA) acknowledges and recognizes the value of the experience gained during an internship. Students who have completed an internship program are granted one year of engineering experience credit towards the experience requirement for professional engineer registration.

3.2 Active Recruiting

Recruiting must be a continuous, ongoing process, especially for students and new graduates who are often unfamiliar with potential employers. A common mistake is to wait and start the recruiting only when a staffing position becomes available.

1. Campus Ambassador

The Campus Ambassador (representing an employer) promotes an organization within academic institutions through on-campus relations/recruiting activities such as: career fairs (or career day), employment information sessions, industry tours, industry lectures, and sponsorships.

The Campus Ambassador roles and responsibilities include:

- Be an active member of the Campus Executive Team in developing and executing a strategy for promoting the employer on-campus, and directly support the Campus Recruiting Leader and other executive team members, before and during campus recruiting.
- Promote corporate events on campus, and assist in distributing corporate information and recruiting materials, including corporate publications.
- Create on-campus awareness for corporate internship and full time employment opportunities.
- Serve as the on-campus contact person for the student body as well as career days, job fairs, and pre-recruiting meetings.
- Actively seek and report new opportunities for on-campus exposure for the employer.

2. Career Fairs

Career fairs are an established method for recruiting staff, however, it is important to target a diverse audience. Career fairs associated with academic institutions tend to attract mainly students and recent graduates while the "open market" career fairs tend to attract more experienced people.

The focus of a career fair can vary, from skill sets (e.g. engineering), sectors (e.g. power industry) to new graduates. Considerations should be given to attending a wide range of career fairs. If an employer expands the career fair attendance to include all general events, exposure of the employer will be broadened in the following areas:

- Introduces and promotes a business to people that may not be familiar with the organization.
- Attendees who are directly interested may forward information to friends and contacts.
- Creates awareness for people with transferable skills who are currently working in different industries.

3.3 Leveraging Academic Alumni

An effective recruiting team should contain members that are similar to the people attending the career fair. For example, new graduates and former interns/co-op students should be part of the recruiting team at a career fair held at an academic institution.

For on-campus recruiting, it is advantageous to have an employee, who is a recent alumnus of that academic institution, as a member of the on-site recruiting team. Since this employee is very familiar with the campus, the academic programs, the departments, the faculties and the students, the whole recruiting effort will be more efficient and productive.

3.4 Referral Bonus

A Talent Referral Program is a recruiting tool designed to encourage current employees to refer qualified external candidates to fill open positions throughout the business. If the referred candidate is hired, a cash award will be paid to the employee making the referral. One half of the payment will be processed shortly after the new hire's start date, the remainder after 6 to 12 months, providing both the referring employee and new hire are still on the payroll.

Talent Referral Programs are usually associated with experienced staff recruiting. This is also an effective tool for recruiting the next round of co-op and internship students. Allowing the current students to participate in recruiting the next round creates more interest on campus.

4. Fast Track Work Force Training & Development

Accelerating professional development increases an employee's effectiveness by yielding results in a shorter period of time. Mentoring programs promote the transfer of useful knowledge and experience to junior staff. Mentors use every opportunity to teach- in house, in the field and at conferences.

4.1 Training

Having a well designed work force training program in place is very important as it sends the correct message about the employer's strong commitment to develop new talents.

1. In House Training

Formal, classroom style, training is a valuable starting point as it falls in the comfort zone for students and new graduates. Unstructured training must be minimized as too much sends the wrong message. Publishing the curriculum is another essential step in building confidence in the training program.

The design of the formal training component incorporates the introduction and promotion of the power industry and the career paths within. Using a diverse group of instructors, from different industry sectors, is required to represent the various career paths. For example, an electric utility and equipment supplier illustrate the diverse, yet sometime similar, career paths. Using multiple departments and business units within an organization further promotes the diverse career opportunities.

THE GOAL OF THE FORMAL TRAINING IS TO BUILD A BROAD FOUNDATION OF KNOWLEDGE FROM WHICH A CAREER CAN GROW

The goal of the formal training is to build a broad foundation of knowledge from which a career can grow. The program is designed to insure experiences are not limited to an assigned department or organization, for example:

- Students and new graduates assigned to a project integration team should be familiar with the activities of a product development team.
- Protection department members should be familiar with the activities of a SCADA/communications department.
- Students and new graduates with an equipment supplier should have an understanding of careers within a power utility.

More detailed knowledge is acquired through assigned tasks, for example the concept of DCE (Data Communications Equipment) is introduced in the Serial Communications training module, and setting up a specific device will only be done as an assigned task. This allows all of the participants in the program to be introduced to the technology used and the associated career path in SCADA/ communications.

2. On the Job Training

On the job or "hands on" training complements the formal sessions by providing an opportunity to put into practice the lessons learned. Task assignment must be carefully planned to promote continuous development.

Task duration must also be given careful consideration. Short-term tasks are good as they can be used to expose a person to a variety of topics and skills. The short duration also provides the opportunity to complete the cycle- see a task through from start to completion.

Longer duration tasks are equally as important and at least one should be ongoing. Focusing on an assignment for a longer period of time promotes planning and multi-tasking. A long duration task should be chosen for co-op and internship students to align with their academic obligations which are typically in the form of status and project reports.

3. External Training

Employers should take advantage of available job related, structured training. This training is a critical component of the overall development for targeted employees' career placement purpose. Some examples of external training include:

- Power industry related courses provided by academic institutions.
- Power industry sponsored workshops, seminars and courses.
- Short courses organized by technical societies (such as IEEEÒ) and industrial/professional associations.

4.2 Site/Facility Visits

Classroom training and facility visits are complementary activities, each reinforcing the information provided by the other. Learning about a 400 MVA transformer does not fully relate the size of the equipment. Viewing a transformer in a substation switchyard completes the learning experience. One cannot appreciate the size of a 400 MVA transformer without seeing one.

The approach used for formal training is also applied to facility visits. The program should include a diverse range of facility visits, encompassing multiple departments and organizations. Ideally, multiple end users (covering the aspects of transmission, distribution, generation, energy and industrial applications) and equipment suppliers are targeted for site and facility visits, which can include: substation, control center, manufacturing plant and factory acceptance test room.

4.3 Networking

Networking is one of the most effective and frequently used career development techniques. It is never too early to start developing alliances, connections and relationships. Networking at industry and professional events will broaden the exposure to valuable learning and career possibilities.

1. Local Volunteering

When local technical events are held, there are many opportunities to participate and support the local organization. This is a good venue for new comers to interact with industry experts and experienced peers. There are two ways to achieve the desired result; employee volunteering or employer nomination. The experience gained from these events, which can include workshops, seminars, conferences and technical meetings, is not restricted to the technical domain. Other tangible benefits include the following items:

- Developing diverse interpersonal skills by interacting with attendees including international delegates.
- Improve the business understanding of the power industry companies.
- Build self-confidence through peer networking in a social environment.

- Learning professional and communication skills by attending and observing presentations.

2. Conferences

Besides providing opportunities for students and new staff to gain a greater understanding of the power industry, conferences also offer the means for meeting and interacting with a wide range of industry experts. Exposure to end users, consultants, vendors, etc. showcases the broad range of career paths within the power industry.

A common trap is to limit conference attendance to senior or more experienced staff. Everyone is faced with a finite budget for conference attendance and a "smart spending" program can increase attendance level without increasing the overall cost. For example, the cost difference between flying and driving several people from one location to another location, to attend a conference, can be used to include an additional attendee, thereby increasing the benefit for the same cost. This concept had been successfully used to allow students and junior staff to attend the Western Power Delivery Automation Conference and the Western Protective Relay Conference.

TO TRANSFORM A SIMPLE JOB-CONTINUATION INTO A MEANINGFUL CAREER MANAGEMENT, POSITION RESPONSIBILITY AND ACCOUNTABILITY MUST BE MUTUALLY AGREED BETWEEN EMPLOYER AND EMPLOYEE

This concept of staff development through conference attendance must not be limited to local events. Larger and high profile events provide a greater opportunity to learn from and network with peers.

4.4 Mentoring & Fast-Tracking

For the purpose of fast-tracking, on the job mentoring is an essential and critical part of competency development. In addition to providing technical advice to the protégé, the mentor also offers guidance in professional and networking skills, techniques for information gathering and analysis.

Besides the on-going mentoring, one interesting concept is the "pairing of senior engineering leader (mentor) with junior engineering staff (protégé)" for attending conferences. At a technical gathering, a mentor can provide real-life and real-time coaching and support to his/her protégé. As an invaluable benefit to the protégé, the mentor offers face-to-face networking introduction for the protégé to all the peers at the event. For example, one power utility applied this concept at IEEE T&D Conferences (North America) and CIGRE General Sessions (Europe), and the results were very positive.

Job shadowing is another useful method to speed up staff development. By assigning a junior engineering staff to work with a senior technical member of another department for a short period of time will give the junior staff a brief insight of other departments.

Another fast-tracking tool is the appointment of an EIT (Engineer In Training) coordinator. This appointee (a mid-level engineer) is accountable for managing the EIT program and assisting the company orientation program, by providing technical and administrative assistance. As a win-win situation, the EIT coordinator will develop leadership skills while the EIT's will have the necessary guidance and support.

5. Strengthen Work Force Retention

If the power industry follows the strategic approach outlined earlier, the work force supply pool will be adequate and sustainable, career entry for new technical staff will be effective and orderly, work force training and career development will be efficient, timely, proactive and productive. When all these efforts produce an appropriate work force, the next question is how to minimize turnovers or early exits. In other words, power industry got the people they need, but what is the power industry doing to make the people stay (or in other words, to keep the people)?

With the ultimate intent of retaining the work force to look after a successful business, power industry needs to address the following aspects:

5.1 Career Management

For an employee to proactively manage his/her career, this individual needs to know the career progression inside the organization. If the employer has a clear and visible process for career advancement, such as a company policy, this would certainly help the employee to know what position level he/she is at, and how to move to the next higher level. This policy must clearly state all the available position levels in the organization; requirements, qualifications and criteria for each level; and the advancement procedure to move from one level to the next. This will become a road map for the employee to follow in order to achieve a successful career. For example, a well-defined and formally declared company policy on "Engineer Level and Development" in one power utility actually lists the engineer levels from Entry Level EIT (Engineer in Training) to Advanced Specialist (i.e. Chief Engineer). In addition, it also specifies the timing and process for promotions.

To transform a simple job-continuation into a meaningful career management, position responsibility and accountability must be mutually agreed between employer and employee. Performance expectation needs to be clearly communicated to the employee, and the employee must plan and execute his/her actions to align with the expectation of the employer.

Regular and timely feedback on job performance is very important in terms of career progression and management, besides the annual performance review. For a well-designed performance review and development (PRD) process, the following activities need to be implemented:

- Beginning of the year: Clear goals and the associated activities need to be established and agreed between the employee and the employer. A formal record will be required to document the goals and activities.

- End of the year: The employee needs to list all the results of the activities identified at the beginning of the year. Then, the employer and the employee will jointly review the results to determine if the identified goals are met. A formal record will be required to document the goals, activities and results.

The bottom line is that, a well-run performance assessment needs to be open, clear, fair and timely. In addition, both the employee and employer must have a common understanding of the performance expectation.

5.2 Encouragement on Professional & Technical Exposure

With respect to career advancement, technical committee participation is beneficial to both employers and employees. The output of these committees is typically a standard or technical publication, however, it is often unclear what the committee's intentions are. Supporting the involvement of an employee allows an employer to know the details of the journey that resulted in the publication. Knowing how and why a decision was made is always better than just knowing what the decision is.

For an employee, participating in a technical committee reflects the acceptance from one's peers and the industry. Committee work raises the profiles of the employee and employer, especially with organizations with international coverage. Conference organizing committees provide a unique opportunity for employees and employers to gain insight into industry practices.

Other opportunities for professional and technical exposure are volunteering in technical organizations and professional societies. Examples are as follows:

- Volunteering for local IEEE section or chapter is a good investment in terms of getting to know the peers in various industries and also letting other like-minded professionals to know the volunteer. Building professional relationship amongst peers and learning the operations of the organizations are definitely some of the desirable benefits.

- Volunteering for technical events (such as workshops, seminars, conferences, etc.) held locally is another excellent way to meet new peers and friends, to gain new experience and to learn new things.

These volunteering opportunities will further enhance peer networking and personal skills development, especially leadership skills that are extremely useful for the employee.

5.3 Continuous Learning and Development

With respect to career advancement, technical committee participation is beneficial to both employers and employees. The output of these committees is typically a standard or technical publication, however, it is often unclear what the committee's intentions are. Supporting the involvement of an employee allows an employer to know the details of the journey that resulted in the publication. Knowing how and why a decision was made is always better than just knowing what the decision is.

5.4 Work Life Balance

Nowadays, employees in any organization are under a lot of stresses at work and at home. These are the result of rapid and frequent changes in workplace and technologies, fast pace life style, non-stop connectivity, information overload and various social pressures. To maintain a healthy work force, any organization must pay genuine attention to the work-life balance of the employees. In order to achieve this balance, flexible work arrangements are effective means.

Flexible work arrangements assist a company in attracting and retaining valued employees by leveraging flexible work schedules to create an inclusive environment that encourages growth for both the business and the employees. Existing and potential employees generally want work time flexibility and employer support to meet a variety of needs. There are several flexible work arrangements that can be implemented, and they are as follows:

- **Flextime:** Full-time employees vary the start and end times of their workdays. Flextime is a low-cost option to introduce and maintain, and it can have great benefits in terms of improved morale and greater productivity.

- **Compressed workweek:** Employees compress a full-time workload into fewer than five days per week. Wherever state or local law/country requires overtime to be paid after 8 hours, compressed workweeks will not be offered.

- **Reduced hours:** Reduced hours is an option where an employee may work 30 hours or more and maintain full benefits. An employee working reduced hours is considered a full- time head for staffing purposes.

- **Part-time work:** Employees reduce their workload and consequently their hours decrease to fewer than the standard workweek requirements with a corresponding reduction in pay and adjustment of benefits.

- J**ob sharing:** Two employees with reduced workloads and corresponding reduced schedules share the responsibilities of a single full-time position. It is a variation of a part-time arrangement and each job sharer is individually on a reduced schedule; part-time policies apply.

- **Telecommuting:** Employees perform full-time work responsibilities up to several days a week at sites other than their primary location – usually their home or a satellite office.

- **Remote work:** Employees perform full-time work responsibilities exclusively from a location outside the primary work site – usually their home or a satellite office.

Depending on the employee's particular situation, one of the above mentioned flexible work arrangements might be an ideal work structure to have. If the employer is open for this arrangement, the employee will certainly be less stressful, and work force retention will be easier to achieve.

5.5 Succession Planning

To run a successful business in the power industry, there needs to be an adequate work force. More importantly, the complements within the work force must be at the appropriate levels in terms of capabilities and accountabilities. Therefore, succession planning needs to be proactive and must also take into consideration the existing work force structure and positions. As indicated earlier, employers should make the accountabilities and qualifications for all positions known and visible to employees. They should also think ahead and develop a realistic and functional succession plan. This plan would have potential candidates identified for various position moves (usually in terms of promotions). Once the plan is in place, the employer needs to discuss the potential career moves with the identified candidate. By doing this, the employee will know the possibility and opportunity of career advancement, and the employer will know the "acceptance and success" level of the plan. This key activity will strengthen the work force retention for sure.

5.6 Employee Benefits

For an employee to stay with an employer, the employee must be satisfied with the overall offering from the employer. This overall offering covers a lot of tangible and intangible items. Employment benefits from an organization are some of the items employees are very interested in. These benefits can include the following listings:

- **Health and dental care** – to offset the cost for prescription drugs, eye glasses, dental check up and required works, ambulance ride and hospital stays
- **Health spending account** – to pay for eligible health or dental expenses that are not covered by insurance
- **Employee life insurance** – employer paid insurance for employee up to two times the annual earnings
- **Government health care** – employer and employee jointly paid health care insurance for employee and his/her family
- **Out of country medical emergencies coverage** – insurance to protect the employee and his/her family for medical emergencies while away from the country
- **Short term & long term disability** – employee coverage against illness lasting a prolonged period
- **Retirement savings** – various forms of pension plans and retirement saving plans
- **Education assistance** – financial support provided by employer to offset the cost of further education for the purpose of career advancement
- **Company scholarship** – financial support provided by employer to support higher education for children (or grand children) of the employees
- **Annual vacation** – paid time-off every year for employee to enjoy
- **Sabbaticals** – half paid leave up to eight weeks, offered to employee at regular intervals (e.g. 4 years)
- **Earned rest days** – one day-off per month for employee to take to address personal needs
- **Memberships** – professional memberships paid by employer for employee, including technical society membership if applicable
- **Incentive pay** – annual bonus payment depending on job performance and business results
- **Wellness fund** – financial reimbursement for expenses on fitness and wellness activities
- **On-site fitness facility (Gym)** – employer sponsored on-site facility for employee use
- **Networking Friday afternoon** – monthly, employer sponsored, for employees to interact and socialize

It should be noted that not all employers provide all the above benefits. An employer may select a combination of the benefits from the above listings. If benefits offered with employment are expanded or enhanced, the employee will be more satisfied with the overall offering from the employer, and this will further reinforce work force retention.

5.7 Retirement

As indicated in the "Increase the Size of the Work Force Supply Pool" section, typical demographic in a power utility shows mainly two groups, namely the veterans and the rookies. In order to keep the veterans working in the power utility as long as possible, for the purpose of knowledge transfer or technical guidance, a phasing retirement program is a very reasonable and attractive tool. The potential retiree may be offered a reduced work schedule, such as three days a week, for a period of time before full retirement. The advantage of this arrangement to the potential retiree is to phase in the upcoming retirement at a slower and controlled rate. The benefit to the employer is the continuation of service provided by the potential retiree. If this program is carried out appropriately and proactively, this will strengthen the capability of the work force without any major disruption.

An employer should be open to the concept of leveraging retirees from other companies within the power industry. To be effective in this approach, the employer needs to be flexible to adjust the time (reduced work hours), location (off site) and assignment (the task acceptability may be very selective) to accommodate the special desire of the employee. Employers need to value and appreciate the proven expertise provided by these employees and should take every opportunity to maximize the benefits.

6. Conclusions

The work force shortage can be addressed by increasing the size of the work force pool, attracting new talent, fast tracking development and retaining experienced personnel. Increasing the size of the work force pool is approached by introducing and promoting careers within the power industry. Encouraging career entry must start with students through partnership programs with academic institutions. Work force development is most effective when it is addressed by the industry, not a single employer. End users and suppliers working together can develop a more versatile work force. Strong retention programs insure the investment in attracting and developing talent is not lost.

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9. Nomenclature

APEGGA	Association of Professional Engineers, Geologists, and Geophysicists of Alberta
APIC	Alberta Power Industry Consortium
CIGRE	Conseil International des Grands Reseaux Electriques - International Council on Large Electric System
EIT	Engineer in Training
iCORE	Informatics Circle Of Research Excellence
NSERC	Natural Science and Engineering Research Council of Canada
PRD	Performance Review and Development
SCADA	Supervisory Control and Data Acquisition

HardFiber™ System

IEC 61850

Process Bus Solution

The Multilin HardFiber System was specifically designed to break the bonds of copper cabling by reducing capital costs, and freeing highly skilled utility workers from performing labor-intensive activities.

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By eliminating the need to install and maintain thousands of copper wires, utilities can save up to 50% of protection and control installation and maintenance costs, while at the same time increasing worker safety and power system reliability.

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Substation Automation Hybrid

Randy Kimura
GE Digital Energy

Abstract

IEC® 61850 is revolutionizing the integration of protection and control through the introduction of new concepts and technologies. Deploying complete IEC 61850 systems is often not immediately feasible due to economic or technology limitations. A hybrid (IEC 61850 in combination with alternate technologies, for example IEC 60870-5-103, can be initially deployed with the long-term goal of evolving into a complete IEC 61850 system.

Greenfield projects provide an opportunity to design and deploy IEC 61850 substation automation systems. Although the design is typically "from scratch," it may not always be possible to use only IEC 61850 devices. Some examples where non-IEC 61850 devices must be used are:

- IEC 61850 is readily available for protection relays, however, IEC 61850 may not be readily available for non-protection IEDs; for example, the preferred transformer monitoring and diagnostic device may not support IEC 61850.
- A specific IED model that does not support IEC 61850 may be required. One example occurs when a non-IEC 61850 protection relay, at the other end of transmission line, is being matched.

Brownfield projects may also provide an opportunity to deploy IEC 61850-based systems. It would be unusual for all of the existing protection and control devices to be replaced with IEC 61850 devices. Economics and user confidence would dictate the reuse of some installed equipment with the addition of some IEC 61850 devices.

This paper will discuss hybrid substation automation solutions, concentrating on the inclusion of alternate technologies. The discussion includes additional IP-based communications, but also extends to non-IP communications thereby allowing the user to maximize equipment reuse and select best in class equipment for their particular situation. Evolutionary scenarios are used to highlight the conversion from alternate technologies to IEC 61850.

1. Introduction

IEC 61850 Substation Automation Systems is no longer wishful thinking. Although process bus implementation has been slow, the station bus has been delivered for years and is widely accepted. A typical IEC 61850 solution, shown in Figure 1, incorporates IEC 61850 Client/ Server, GOOSE and GSSE communications on to a substation LAN.

IEC 61850 Substation Automation Systems can be designed for new systems, replace or retrofit existing systems, and expand an existing system. The goal must always be to use the best available device to meet the user's requirements. The best available device is not always IEC 61850 enabled.

IEC 61850 SUBSTATION AUTOMATION SYSTEMS CAN BE DESIGNED FOR NEW SYSTEMS, REPLACE OR RETROFIT EXISTING SYSTEMS, AND EXPAND AN EXISTING SYSTEM

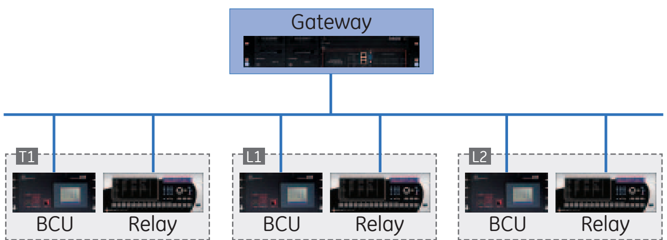

Figure 1.
IEC 61850 Substation Automation System

A hybrid solution is not limited to IEC 61850; additional communication and interfacing technologies are used. The alternate technologies can range from the physical interface to the communication protocol.

2. Greenfield/Replacement

Greenfield projects provide an opportunity to design and deploy IEC 61850 substation automation systems. Complete retrofit Brownfield projects may also provide an opportunity to deploy IEC 61850-based systems. In a complete retrofit all of the existing equipment can be removed. Although the design is typically "from scratch," it may not always be possible to only use IEC 61850 devices.

A suitability evaluation insures it is appropriate to select an IEC 61850 device. Protection scheme coordination, Operation & Maintenance requirements, and user qualification are included in a suitability evaluation.

A protection scheme may be required to match the protection relay installed at the opposite end of the transmission line. The Substation Automation System must be able to adapt when the protection relay already installed at the opposite end of the transmission line does not support IEC 61850. In an ideal situation, the protection relay at the opposite end of the transmission line can be upgraded to, or replaced with, an IEC 61850-capable model thereby allowing the Substation Automation System to remain a "pure" IEC 61850 solution. The ideal scenario is often not possible with non-IEC 61850 protection relays installed at both ends of the transmission line.

Operation and Maintenance concerns can also influence device selection. Examples potentially preventing a device model change include:

- Additional utility personnel training may be required to support a new device model. Coordination of the training can be complicated due to the variety of topics; examples include settings or configuration modification, installation, trouble shooting, diagnostics and repair.
- Sourcing and deployment of the new device's engineering tool may be required to a variety of utility personnel; examples include systems engineers, configuration technicians and field service engineers. In some instances, the cost of the software licenses can be prohibitive. Newer software tools often have increased system requirements that require personal computer hardware and operating system upgrades or replacement.
- The stocking and deployment of spare components is complicated by the addition of a new device.

A typical Substation Automation System can only deploy devices that have been previously tested and approved for use by the end user. Although IEC 61850-capable devices may be available for a particular function, an IEC 61850-capable device may not be available on the approved list of devices. Ideally, an IEC 61850-capable device can be qualified and added to the approved list of devices. Device qualification is often not possible within the required time frame.

Substation Automation Systems were initially designed to incorporate protection and control devices. Additional functionality may also be incorporated; for example, monitoring and diagnostic devices can be integrated into Substation Automation Systems. A Transformer monitoring IED will be added to the example system being studied. IEC 61850 is readily available for protection relays, however, IEC 61850 may not be readily available for non-protection IEDs; for example, the preferred transformer monitoring and diagnostic device may not support IEC 61850.

The following discussion studies single bay solutions and may be extended to include the entire Substation Automation System. The focus is from a protection and control point of view, however, the solutions can be applied to include additional functions. For example, any referenced protection relay could be replaced with a monitoring and diagnostic IED.

2.1 Hardwired Connection

The use of a hardwired interface to transfer information between two devices is a fundamental approach that has been successfully deployed for many years. Reducing copper wiring is one of the benefits initially identified for IEC 61850 Substation Automation Systems. This hardwired approach is contradictory; increasing the associated copper wiring engineering, installation and maintenance costs.

The example, shown in Figure 2, uses a hardwired interface between a protection relay and a BCU. The IEC 61850- capable BCU functions as an IEC 61850 server for the protection relay.

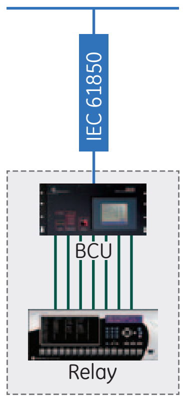

Figure 2.
Harwired

Additional factors to consider when contemplating a hardwired interface include:

- Additional networking infrastructure is not initially required. Networking equipment costs are deferred and will only be applied for an IEC 61850 upgrade.
- Minimal configuration of the BCU and IED is required for the hardwired interface.
- Accurate event reporting requires the BCU to time stamp the hardwired relay data with 1 millisecond accuracy.

2.2 Serial Communication Interface

The use of a serial communication protocol to interface two devices is another solution that has been successfully deployed for many years. Examples of commonly used serial communication protocols include:

- IEC 60870-5-103
- DNP3
- Courier
- Modbus® RTU and Modbus ASCII

Many IEDs support multiple serial communication protocols. The available serial communication protocols must be evaluated against the system requirements. Items to evaluate include:

- Time stamped data reporting capability varies for communication protocols. Most modern serial communication protocols support event reporting, however, a validation is still required as some protocols do not explicitly support SOEs (e.g., Modbus). Protocol evaluation is also required for the reporting of time stamped measurements and accumulated values, as many protocols do not support this functionality.
- Time synchronization is required when time stamped data is reported. The communication protocol and associated infrastructure (e.g., DCE hardware) must be evaluated to insure accurate time synchronization. This evaluation is not required when alternate time synchronization methods are used (e.g., IRIG-B).
- System performance is impacted by the data reporting method. Traditional polled/response data retrieval is the least efficient method. Report by exception techniques improve bandwidth efficiency by only transferring data that has changed.
- A system with significant quantities of measurement data will benefit from a communication protocol that supports deadbanding. Deadbanding will filter minor changes thereby improving bandwidth efficiency.

The solution, shown in Figure 3, uses a serial communication interface between a protection relay and a BCU. The IEC 61850-capable BCU functions as an IEC 61850 server for the protection relay.

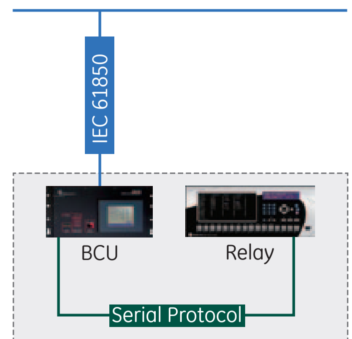

Figure 3.
Serial Communication

Additional factors to consider when contemplating a serial communication interface include:

- Additional networking infrastructure is not initially required. Networking equipment costs are deferred and will only be applied for a IEC 61850 upgrade.
- Additional DCE equipment may be required (e.g., modems, media converters).
- Configuration of the IED server and BCU Client is required for the serial communications.

Multiple devices can be interfaced to the BCU when an addressable communication protocol is used.

2.3 Alternate IP Communications

The use of an IP communication protocol interface is the most recently adopted of the studied solutions. Examples of commonly used alternate IP communication protocols include:

- IEC 60870-5-104
- DNP3/TCP/IP and DNP3/UDP/IP
- Modbus TCP/IP

Many IEDs also support multiple IP communication protocols; an evaluation, similar to the evaluation described for serial communication protocols, is required.

The solution, shown in Figure 4, uses an alternate IP communication protocol to interface the protection relay on to the station bus.

Additional factors to consider when contemplating an alternate IP communication protocol interface include:

- Upgrading to IEC 61850 will be a simpler exercise for devices that support IEC 61850 in addition to the alternate IP communication protocol. Upgrading the device to IEC 61850 is typically limited to a firmware change; the communication infrastructure is already in place.
- Additional networking infrastructure (e.g., switches) may be required, however, this equipment is reusable for an IEC 61850 upgrade.

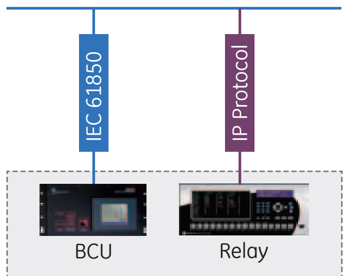

Figure 4.
Alternate IP Communication

3. Retrofit

Brownfield projects provide an opportunity to upgrade, part or all of, a Substation Automation System to IEC 61850. The interface methods (hardwire, serial communication, IP communication) described for Greenfield projects can be applied to the existing system. The Greenfield project device selection criteria are also directly applicable for retrofit projects.

The existing Substation Automation System can consist of:

- All of the IEDs are integrated using one or more serial communication protocols.
- All of the IEDs are integrated using one or more IP-based communication protocols.
- The IEDs are integrated using both serial and IP- based communication protocol.

3.1 Retrofitting a Serial Communication Based System

A serial communication-based Substation Automation System can be challenging to upgrade to an IEC 61850 solution. A substation LAN must be added to the existing system.

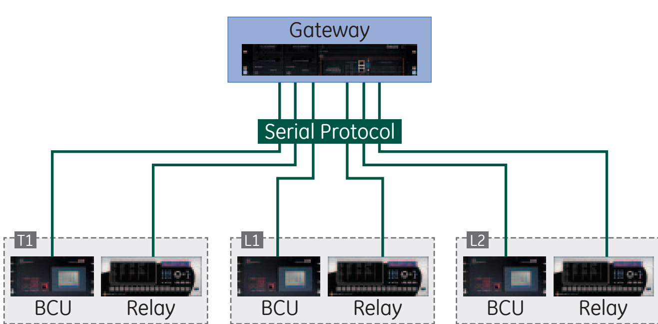

Figure 5.
Serial Communication Substation Automation System

Serial IEDs are individually evaluated to determine the suitability for a IEC 61850 migration. The following interfaces have been identified to connect a device to the substation LAN:

- Upgrade the installed device to interface directly to the substation LAN using IEC 61850. Although this option produces the ideal solution, it requires careful planning as the devices' physical layer must be changed (serial to Ethernet).
- Upgrade the installed device to interface directly to the substation LAN using an alternate IP communication protocol. This solution also requires a change to the devices' physical layer.
- Use a serial communication protocol to interface using an intermediary IEC 61850 device.
- Hardwire the installed device to an intermediary IEC 61850 device.

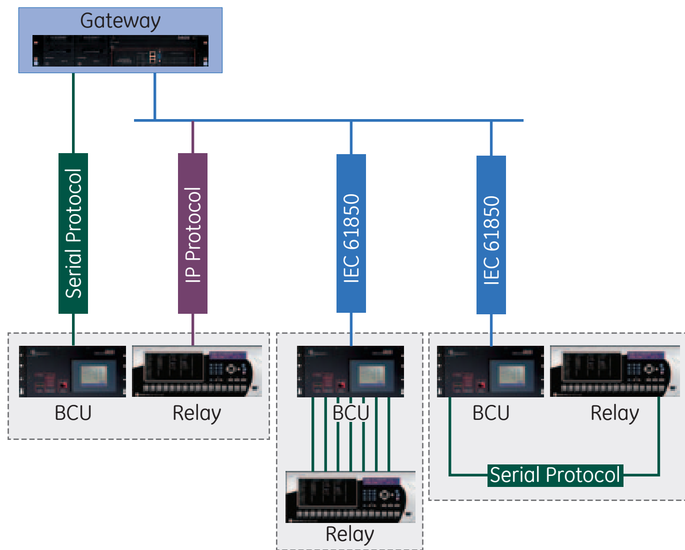

Figure 6.
Retrofitted Serial System

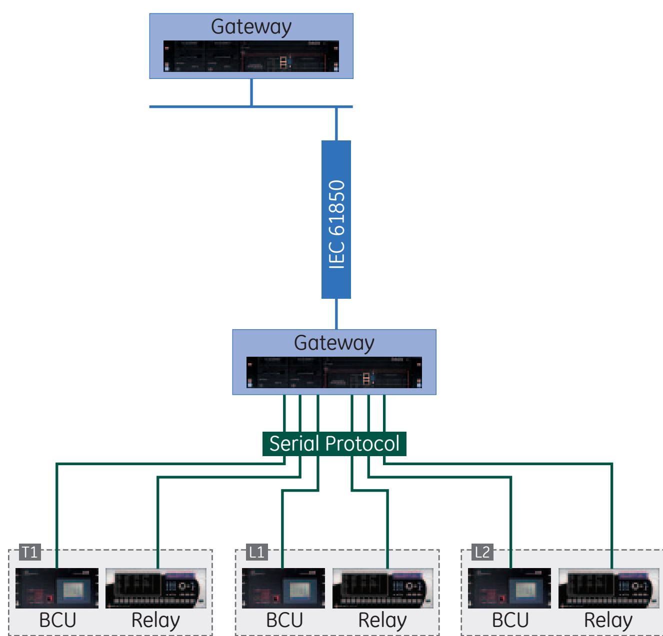

Figure 7.
Dual Gateway Hybrid

Figure 6 shows the hybrid system after the upgrades have been applied the original system shown in Figure 5. The hybrid solution has serial and IP communications to the gateway. The IP communications use IEC 61850 and non-IEC 61850 communication on the station bus. The BCUs in L1 and L2 have been upgraded to directly interface using IEC 61850. The relay in T1 has been upgraded to interface using an alternate IP communication protocol. The relay in L1 uses a hardwire interface to an IEC 61850 enabled BCU. The relay in L2 uses a serial communication protocol to interface via an IEC 61850 enabled BCU. The BCU in T1 is unchanged and continues to use the original serial communication protocol to the gateway.

THE LEAST INVASIVE APPROACH IS TO MAXIMIZE THE REUSE OF THE INSTALLED EQUIPMENT AND ADD IEC 61850 DEVICES FOR THE NEW LINE

An alternative approach is to add a second gateway dedicated to the substation LAN. The existing system is interfaced to the substation LAN using the original gateway. This architecture, shown in Figure 7., is the starting point for the IEC 61850 migration. An evaluation of the installed devices is used to identify the IEC 61850-capable devices that are suitable for direct connection to the substation LAN.

3.2 Retrofitting a IP Communication Based System

Retrofitting an entirely IP communication-based Substation Automation System is simpler than a serial communication-based system. The existing substation LAN can be reused which simplifies the engineering effort required to support the upgrade.

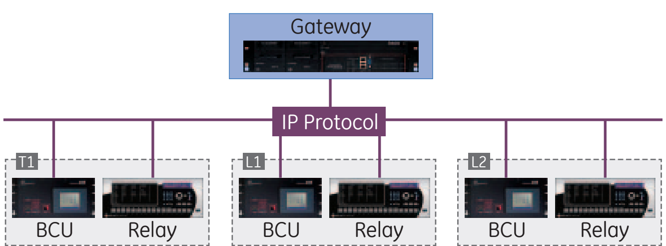

Figure 8.
IP Communication Bases Substation Automation System

The first step when upgrading an existing IP communication-based system is to identify any installed devices that can be directly upgraded to IEC 61850. These devices require the least amount of effort to upgrade. A suitability evaluation is required for the devices targeted for the IEC 61850 upgrade. All suitable and upgradeable devices will use IEC 61850 connectivity on the substation LAN.

In an ideal situation, all of the installed devices are upgraded to support IEC 61850. A suitability evaluation must be performed for any remaining devices to determine if the installed device can be replaced with an IEC 61850-capable device. The suitability of replacing a device must be evaluated using the same criteria discussed for Greenfield projects.

4. Expansion

Brownfield projects may also provide an opportunity to deploy IEC 61850-based systems. It would be unusual for all of the existing protection and control devices to be replaced with IEC 61850 devices. Economics and user confidence would dictate the reuse of some installed equipment with the addition of some IEC 61850 devices.

Consider a substation with one transformer (T1) and two outgoing lines (L1 and L2). An expansion project will add a third outgoing line (L3). The existing Substation Automation System integrates the T1, L1, and L2 IEDs using serial and/ or IP based-communication protocols. The expansion project will add the IEDs for the new line and start migrating the Substation Automation System towards an IEC 61850 solution.

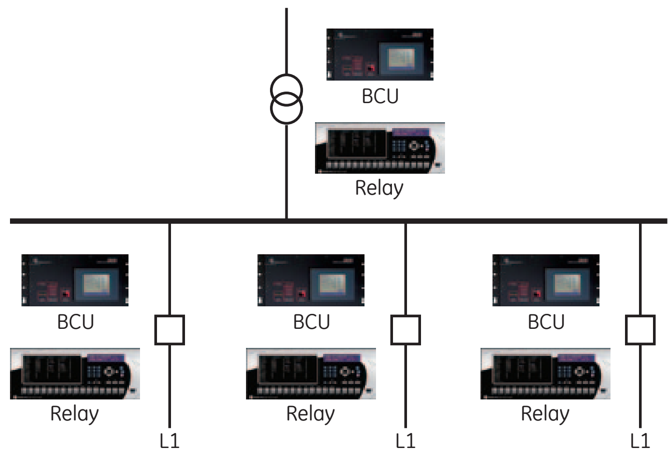

Figure 9.
Substation Expansion

The least invasive approach is to maximize the reuse of the installed equipment and add IEC 61850 devices for the new line. This is always a good first step as it provides a snapshot of the Substation Automation after the station bus has been added. An evolutionary approach can follow; upgrading or replacing installed devices to an IEC 61850 solution. Additional factors to consider when reusing installed equipment include:

- Minimal engineering effort will be required for the existing equipment.
- Installation and commissioning is primarily focused on the new line thereby minimizing the overall effort required.
- Using the in stock spare components minimizes operation and maintenance of the new system. Additional Operation and maintenance costs are limited to spare components and resource training for new devices.

The existing Substation Automation System can consist of:

- All of the IEDs are integrated using one or more serial communication protocols.

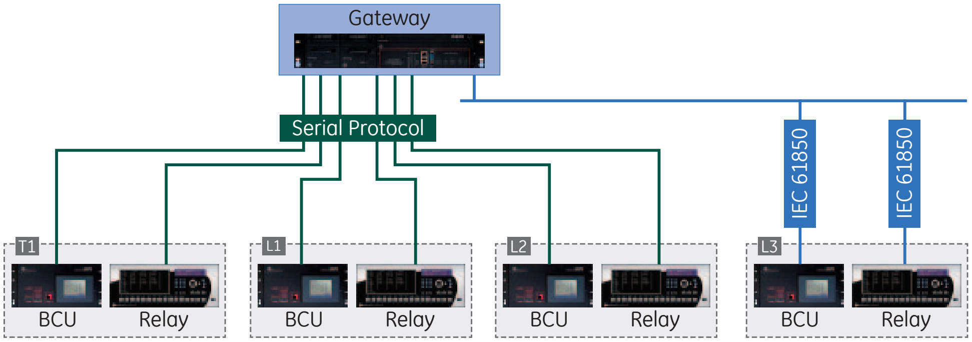

Figure 10.
Serial/IEC 61850 Hybrid

- All of the IEDs are integrated using one or more IP- based communication protocols.
- The IEDs are integrated using both serial and IP- based communication protocols.

4.1 Expanding a Serial Communication Based System

The difficulties to be considered when upgrading a serial communication-based Substation Automation System to an IEC 61850 solution has been previously described for a retrofit. The expansion of a substation is effectively a retrofit with some new equipment added.

The addition of the new devices will add a substation LAN to the existing Substation Automation System. Although the substation LAN only supports IEC 61850, the overall solution is a hybrid simultaneously supporting serial and IEC 61850 communications.

The previously described migration techniques can be applied to migrate the installed devices to IEC 61850.

4.2 Expanding an IP Communication Based System

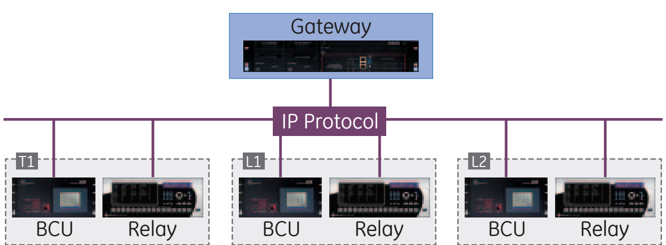

Figure 11.
IP Communication Substation Automation System

An existing IP communication-based Substation Automation System can be simpler to upgrade than an entire serial communication-based system. The existing substation LAN is used to interface the IEC 61850 devices.

The new devices will interface to the existing substation LAN. The resulting hybrid substation LAN will simultaneously support IEC 61850 and alternate IP-based communication protocols.

The previously described migration techniques can be applied to convert the installed devices to IEC 61850.

7. Conclusions

Although a complete IEC 61850 approach may be desirable, it is often not possible to deploy these systems. Hybrid Substation Automation Systems, IEC 61850 in conjunction with alternate technologies, can be applied to Greenfield, complete replacement, retrofit and expansion projects. IED selection constrained by IEC 61850 capability is not always possible; deploying a hybrid solution allows a user to select the most appropriate devices for the required task. A hybrid Substation Automation System provides a foundation that can be evolved to a complete IEC 61850 solution.

8. Nomenclature

BCU	Bay Control Unit
DCE	Data Communication Equipment
GOOSE	Generic Object Oriented Substation Event
GSSE	Generic Substation State Event
LAN	Local Area Network

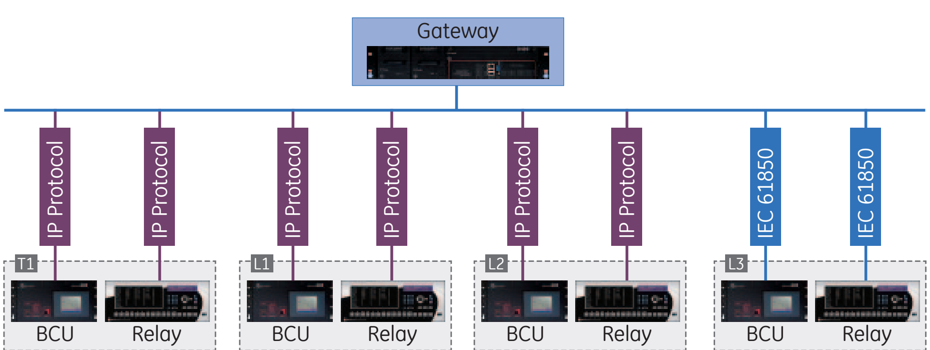

Figure 12.
Hybrid Substation LAN

Secure Substation Automation for Operations & Maintenance

Byron Flynn
GE Energy

1. Abstract

Today's Cyber Security requirements have created a need to redesign the Station Automation Architectures to provide secure access for Operations and Maintenance Systems and Personnel. This paper will review several architectures being used and planned by utilities today.

Several real world architectures will be reviewed including:

1. Serial SCADA & Dial-up Maintenance,

2. Serial SCADA & LAN based Maintenance,

3. Combined LAN for SCADA and Maintenance and;

4. Separate SCADA WAN/LAN and Maintenance WAN/LAN.

Each architecture will include various methods of User authentication and secure access to various station IEDs including relays, meters, RTUs, PLCs and station servers. This will include configuration access, maintenance access, and manual and automatic data retrieval of fault data.

2. Background

In August of 2003, NERC issued the Urgent Action Cyber Security Standard 1200. This standard was set to expire in August of 2005 but was given a 1 year extension. A new standard originally called Standard 1300 and now named the NERC Critical Infrastructure Protection (CIP) Cyber Security Standard.

As of January 16, 2006, the current version of the document is Draft 4 [1]. The section headings are:

CIP-002 Critical Cyber Asset Identification

CIP-003 Security Management Controls

CIP-004 Personnel and Training

CIP-005 Electronic Security Perimeter(s)

CIP-006 Physical Security

CIP-007 Systems Security Management

CIP-008 Incident Reporting and Response Planning

CIP-009 Recovery Plans for Critical Cyber Assets

According to NERC:

Bulk Electric Systems are "defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." [2]

Critical Assets are those "facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System." [3]

Critical Cyber Assets are "Programmable electronic devices and communication networks including hardware, software, and data." [4] "Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:

R3.1. The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,

R3.2. The Cyber Asset uses a routable protocol within a Control Center; or,

R3.3. The Cyber Asset is dial-up accessible." [5]

3. Definitions [6]

3.1 Certificate Authority

A certificate authority or certification authority (CA) is an entity which issues digital certificates. In cryptography, a public key certificate (or identity certificate) is a certificate which uses a digital signature to bind together a public key with an identity – information such as the name of a person or an organization, their address, and so forth. The certificate can be used to verify that a public key belongs to an individual.

CHAP

Challenge Handshake Authentication Protocol is an access control protocol for dialing into a network that provides a moderate degree of security. CHAP uses encryption of random values with the client's password for authentication.

HTTPS

Hyper Text Transport Protocol Secure is a secure version of HTTP, the communication protocol of the World Wide Web, invented by Netscape Communications Corporation to provide authentication and encrypted communication. Instead of using plain text socket communication, HTTPS encrypts the session data using either a version of the SSL (Secure Socket Layer) protocol or the TLS (Transport Layer Security) protocol, thus ensuring reasonable protection from eavesdroppers, and man in the middle attacks.

3.2 Identification Factors

There are generally four Identification Factors that are used for authentication. None of them are entirely foolproof, but in order of least to most secure, they are:

1. What You Know – passwords are widely used to identify a User, but only verify that somebody knows the password.
2. What You Have – digital certificates in the User's computer add more security than a password, and smart cards verify that Users have a physical token in their possession, but either can be stolen.
3. What You Are – biometrics such as fingerprints and iris recognition are more difficult but not impossible to forge.
4. What You Do – dynamic biometrics such as hand writing a signature and voice recognition are the most secure; however, replay attacks can fool the system.

PKI

Public Key Infrastructure is an arrangement that provides for third party vetting of, and vouching for, User identities. It also allows binding of public keys to Users. Public Keys are typically in certificates.

PPP

Point-to-Point Protocol is the most popular method for transporting IP packets over a serial link between the User and the ISP. Developed in 1994 by the IETF, PPP establishes the session between the User's computer and the ISP using its own Link Control Protocol (LCP). PPP supports CHAP authentication.

SSL

Secure Sockets Layer is the primary security protocol used on the Internet. Originally developed by Netscape, it validates the identity of a website and provides an encrypted connection for transactions. SSL uses HTTPS protocol. Use of SSL requires a certificate from a Certificate Authority.

Secure Connection Relay

In Secure Connection Relay, a client outside the security perimeter establishes an SSL connection with a gateway, which then makes an unencrypted TCP connection to another TCP address on the substation LAN and relays traffic between the SSL connection and the TCP connection.

Secure Terminal Server

In Secure Terminal Server, a client outside the security perimeter establishes an SSL connection with a gateway, which then opens a serial port and relays traffic between the SSL connection and the serial port.

Secure Data Concentrator

This capability provides secure SSL encapsulation for any networked SCADA protocol on the concentrator.

TLS

Transport Layer Security and it predecessor are cryptographic protocols which provide secure communications on the Internet. There are slight differences between SSL 3.0 and TLS 1.0, but the protocol remains substantially the same.

T-F A

Two Factor Authentication requires two authentication factors before accessing a system and is considered strong authentication.

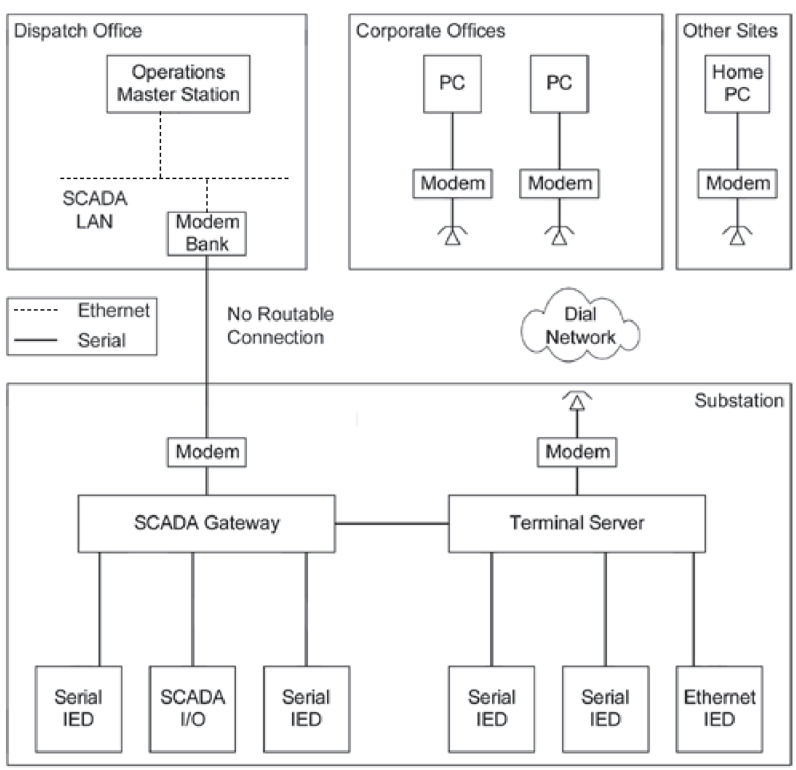

Fig 1.
Existing Architecture.

4. System Architectures

4.1 Introduction

Applying the appropriate level of security to a complex system is one of the biggest challenges utilities are facing today. These challenges are amplified because for security reasons, it is very difficult for utilities to share security best practices outside of the personnel directly responsible with that security. While this paper does not reveal specific architectures being used by any utility, it attempts to outline several typical architectures with various levels of security.

By its nature, security will always be a "cat and mouse" game where new threats require new security methods. Establishing a security strategy also requires a balancing act where any method of restricting access must be balanced with the critical nature of the asset and the limitations placed on employees with substation cyber access rights. It is important and useful to review the various threats to a security system. They are [7]:

- the Hacker. The proverbial teenager just looking to break into things. May not even want to do any damage. They often have a lot of computing power and expertise in corporate networking, but typically will not know anything about power systems or utility protocols.
- the Vandal. Indistinguishable from the Hacker except for motive. Wants to break things, and doesn't really care what. Less common than the Hacker, but more dangerous.
- the Terrorist. This is the attacker people are most afraid of, but is actually less likely to occur than many others. Wants to do specific damage and will probably research the target's network and operations. Would need to know something about power systems and utility protocols. To get this information, could enlist the help of...
- the Disgruntled Employee. This is one of the most dangerous of potential attackers, because they already know the utility's security systems, procedures and weaknesses.
- the Competitor. Utilities are required to communicate with, and therefore share networks with, their competitors. The competitor is probably an uncommon but extremely dangerous threats to the utility network because:
    a) utilities cannot simply prohibit all access, but must limit what data competitors can see.
    b) competitors already know about power systems and probably quite a bit about their target's network.
    c) their attack, if it occurs, will likely be subtle, i.e. eavesdropping rather than denial of service, and therefore harder to detect.
- the Customer. Unfortunately, utilities' customers may also be a threat. They are an especially dangerous threat because they often want to commit fraud rather than to simply damage the electrical network. As noted with competitors, the customer's attack may be hard to detect because all they want to do is modify a few key values.

The following portion of this paper reviews several methods of establishing a secure connection to block unauthorized access and allow appropriate access to the two most common types of data in the substation, often referred to as – SCADA or Operational Data and Maintenance or Non-Operational Data. These architectures are representative of systems in-use or being planned by Utilities today.

4.2 Common System

The Figure 1 contains the most common architecture today for access of substation data for Operations and Maintenance personnel.

The Dispatch office connects to the station over a dedicated communications line using a SCADA protocol. The Maintenance Users connect from any computer with a modem to the IEDs through an unsecured port switch. The Unsecured Port Switch can send data to the SCADA Gateway via a standard SCADA Protocol. The connection is made using a SCADA protocol supported by both boxes, commonly DNP. The SCADA Gateway is typically the master and Port Switch is the slave. This connection is limiting and it can be difficult to share data from the SCADA IEDs with the Port Switch. It is also impossible for User's connecting to the Port Switch to access the SCADA IEDs through that connection. Each device must be connected directly to the Port Switch for the remote PCs to access the IEDs.

The need for a Station LAN increases as additional IEDs support Ethernet communications, such as protective relays, RTUs, PLCs, meters, and DFRs. As Ethernet-based IEDs are added to the substation, the common architecture is changed as shown below to support remote connection to the Station LAN.

4.3 Current Station LAN Architectures

Many IEDs contain the ability to communicate via a LAN port. The Figure 2 contains an initial architecture for access of substation data for Operations and Maintenance personnel.

The Port Switch has been replaced by a Terminal Server, which can provide the ability to connect from a remote PC to serial, or Ethernet devices. This capability is provided using PPP. PPP provides the ability to connect to the Terminal Server with Telnet and then tunnel through to the serial IEDs. The Terminal Server would also allow the remote PC to connect directly to the Station LAN. Many Ethernet IEDs and Terminal Servers can also provide web pages to be viewed by browsers connected locally to the Station LAN or remotely via dial-up.

The SCADA Gateway has also been upgraded to include an Ethernet connection to the Station LAN. This provides the ability to remotely access data from the Ethernet IEDs through the Dial-up Port.

4.4 Security

The Port Switch is typically secured with a password only; the Terminal Server can be secured with login IDs and support CHAP. CHAP provides an increased level of security however, it provides only single factor authentication, anyone who has the password could log into the Station from any modem. Furthermore, the Ethernet devices would not be secured unless routing was disabled in the Terminal Server between the remote connections and the Ethernet IEDs. Then Ethernet access would not be possible remotely.

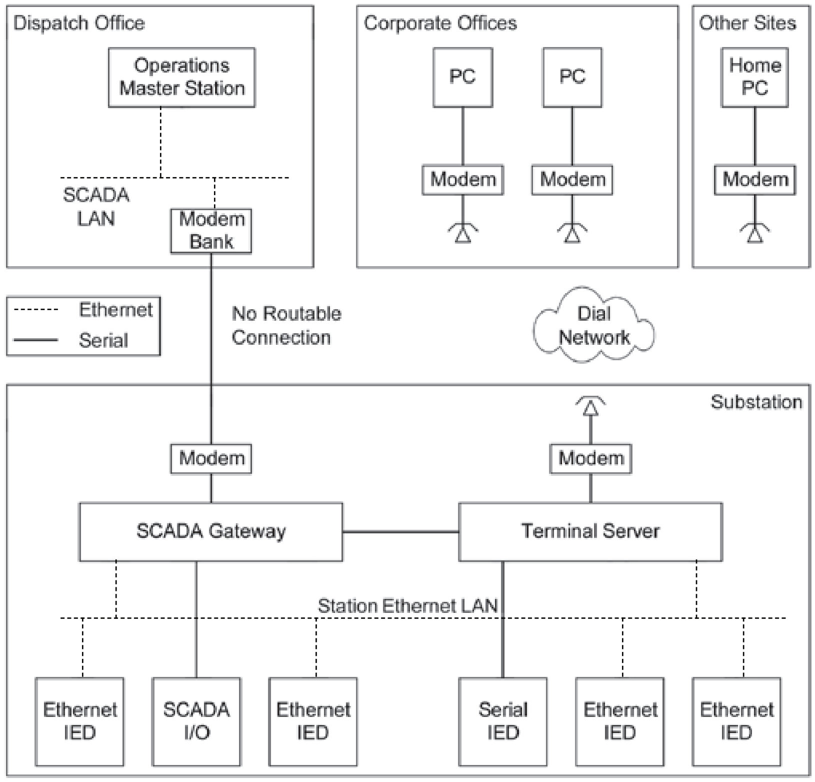

Fig 2.
Existing Architecture with a Station LAN.

5. Secure Architecture #1 – Dial-Up

The gateway meets the NERC security criteria, provides protocol conversion and data concentration for both the Serial and Ethernet IEDs. The gateway also polls those IEDs and concentrates the data in an internal database. Then web pages are generated to display the non-SCADA data providing a convenient tool for viewing fault data from the Stations IED relays together on one web page. Other IEDs can also be displayed including transformer or breaker monitoring and diagnostics, metering, and all the various station analogs including MW loading, voltages, PF, etc.

In order to meet the NERC CIP, two additional capabilities need to be added: the addition of a second authentication factor and the ability to audit successful or unsuccessful login attempts. The architecture shown in Figure 3 illustrates system with the additional NERC CIP functionality.

The system in Figure 3 uses PPP and CHAP providing one authentication factor. SSL and PKI provide a second authentication factor through the use of digital certificates on each PC. Each PC must have SSL and utilize either an additional hardware or software based authorization key before attempting to access the Maintenance Gateway. The Maintenance Gateway will also need to be configured for that User's access and authorization rights. The authorization rights would include rights on the gateway such as View, Control, Configuration or Security Administration and the specific serial or Ethernet IEDs the User is permitted to directly access.

Strong authentication is achieved through the use of the two factors, the User's ID and password (under CHAP) "Something They Know" and either a hardware or software key/certificate "Something They Have".

The gateway also must record and report successful or unsuccessful login attempts. This supports the NERC CIP requirements of "Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days" [8].

A useful tool to enable security administration for this architecture and the subsequent architectures is a Certificate Authority. A Certificate Authority provides a convenient method to manage Certificates for the Gateways, Master Stations or PC Users. Some Gateways come with an initial Certificate valid for a specific period of time after which a new certificate would need to be issued. As new Users request access to the stations a new certificate would be generated for that user. This tool could also generate a revocation list when a user's access rights are removed.

5.1 Remote access to IEDs

Once the User has been authenticated by the Gateway, the Station IEDs can be accessed remotely. Serial IEDs are accessed through serial tunneling software on the Gateway. If the IED software supports Ethernet access, then the serial IEDs are accessed through a serial tunnel established by the Gateway. The User can then access the IED using the IED's native software. The User can connect directly to the IED if that software supports connecting using an Ethernet connection. Otherwise, the User would need to run a virtual serial port software program. That software creates a virtual serial port that the IED software access which redirects the channel to the Gateway and the IED.

The Gateway does control the particular serial and Ethernet IEDs the remote User can access based on their Username and certificate. The serial IEDs are accessed using Secure Terminal Server for the IEDs that the User has authorization to connect. The Gateway also allows an Ethernet connection only to authorized

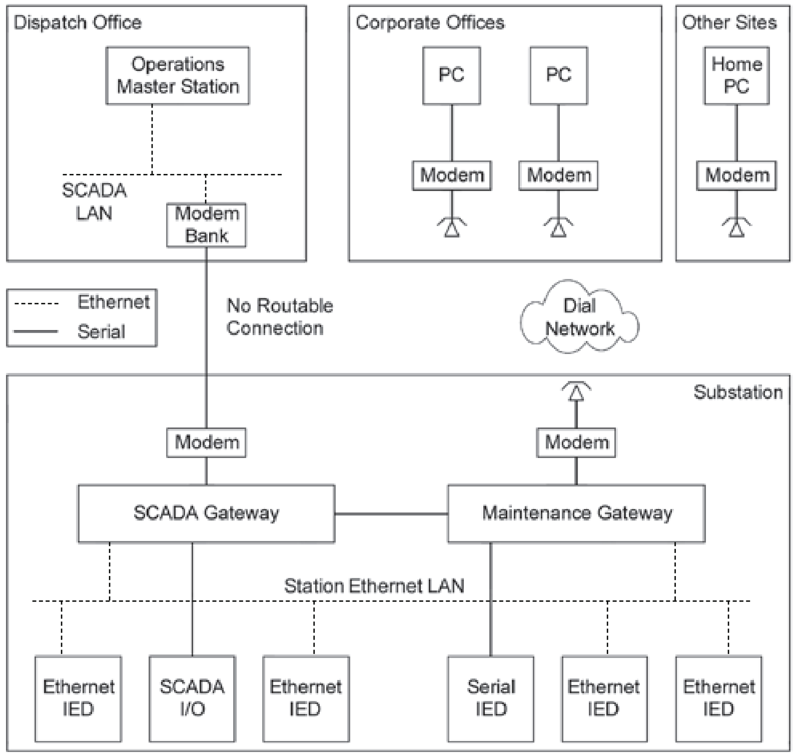

Fig 3.
Secure Dial-Up System.

Ethernet IEDs using Secure Connection Relay. These methods restrict remote User access to only the IEDs that the User is authorized to access.

5.2 System Advantages

This system offers security and flexibility. It is the most similar to the dial-up techniques being used today by many Utilities to remotely access the station's non-operational data and IEDs. This architecture provides capabilities of secure access by authorized Users from virtually any dial line.

5.3 System Disadvantages

This system, however, has some significant limitations. Access speeds can be one of the biggest challenges. Also, this technique requires the use of either hard token for each authorized User or a soft token/certificate installed on each User's PC.

Administration of the system is also very demanding. Each Gateway must contain a listing of authorized Users and their IED access rights. This makes the NERC requirement of removing remote access within 24 hours of termination of authorized employees difficult and time consuming.

6. Secure Architecture #2 – Dial-Up Maintenance Server

A similar architecture that allows for centralized password administration of dial circuits is shown in Figure 4. This architecture includes a Secure Dial-Up Maintenance Server installed behind a firewall and connected to a modem bank. This system provides the ability to connect to the Maintenance Gateway and the Station IEDs using a similar technique as the previous Architecture but includes the convenience of LAN connection by the PCs.

Users connect through the Corporate LAN through a firewall to a Maintenance Server. This server provides two-factor authentication with User ID with Password and SSL with PKI including hard token or soft token/certificate. Additionally, each User must have access to the server through the firewall on the network.

The Maintenance Server can be tied to a central Authentication Server which can support Single Sign On (SSO). SSO allows users to only remember one user-ID and password for the Corporate System and for the Maintenance Server/Gateway. It also allows users to authenticate once to gain access to Corporate resources and the Maintenance Server/Gateway. The Authentication Server also can optionally support one time password package (e.g. RSA SecureID).

While the Authentication Server becomes a centralized authority, the Maintenance Server still manages the User's access rights in each Gateway. When a User wants to log-in to a Gateway over the WAN, the User is authenticated by the Maintenance Server then the access rights are set up with the Gateway. The Gateway tracks successful or unsuccessful login attempts. .

Performing authentication on a central server makes it much easier to meet the following CIP requirement: "The Responsible Entity shall revoke such access to Critical Cyber Assets within 24 hours for personnel terminated for cause and within seven calendar days for personnel who no longer require such access to Critical Cyber Assets" [9].

Once a User is authenticated, the server then presents a pick list of substations and IEDs. The User then selects one of the choices and the Maintenance Server then dials one of the modems to the appropriate Maintenance Gateway in the Station using PPP. The Server maintains a randomly generated Maintenance Gateway Password and the appropriate SSL and PKI soft token/certificate for access to the Gateway. The Maintenance Server sends the

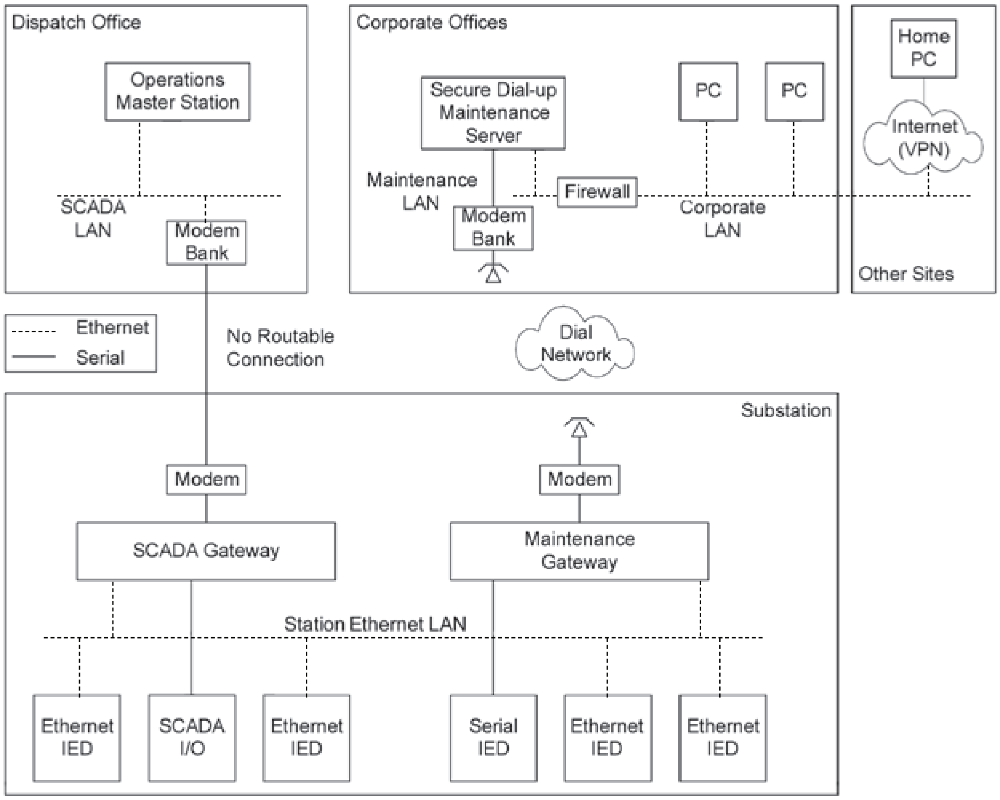

Fig 4.
Serial Maintenance Server.

authenticated User's ID to the Maintenance Gateway for audit trail and sends that User's specific access rights to the Gateway. This allows specific access control for the Gateway's Web Pages, the serial IEDs and the Ethernet IEDs.

The Maintenance Server contains the necessary scripts to establish Gateway pass-through connection to the appropriate IED. Users connecting to the system from a home PC will use their approved method of connecting, usually VPN, to the Corporate LAN and then access the Maintenance Server over that LAN.

As in the previous architecture, the Gateway must maintain a log of success or unsuccessful login attempts for retrieval by the System Administrator.

This method of accessing the system provides some convenience to the Users, as they don't have to remember the phone number for the stations. They also don't need to remember the script necessary to access a particular IED, as the scripts are stored in the Dial-Up Maintenance Server. The Dial-Up Server also randomly establishes and routinely changes the passwords on each Station Gateway. Security is improved since the Gateway's uses a strong password that is kept private.

6.1 Remote access to IEDs

Once the User has been authenticated by the Maintenance Server and the Server connects to the Gateway, the Station IEDs can be accessed remotely by running the appropriate script on the Server. The Server establishes the access control in the Gateway and enables/disables access as appropriate with these scripts. As with the previous architecture, the serial IEDs are accessed through serial tunneling software on the Server and Gateway and Ethernet IEDs are accessed using Secure Connection Relay. These methods restrict remote User access to only the IEDs that the User is authorized to access.

6.2 System Advantages

This system is also secure and flexible and it provides secure access without the requirement of specific Username and Password and maintenance rights at each Gateway because the Maintenance Server provides centralized administration. Whenever the access rights of a User change, the Administrator only changes the Maintenance Server. Significantly reducing the effort required by the Administrator over a system without a Maintenance Server. Users also don't need to learn different access address or IED scripts to connect to remote devices.

6.3 System Disadvantages

This system requires users to have LAN access to the Maintenance Server before they can access the Gateways in the Station. This will require User's to change the method of accessing the system. Two-factor authentication is still required at the Maintenance Server because it has become another secure access boundary to the Stations. This system also has the speed limitations inherent of dial-up access.

If dial-up access is still necessary from multiple sites to the Gateway then both methods need to be administrated on the Gateway and Maintenance Server making the system more complicated. Administrators may desire to provide only a few authorized dial-up users to operate only as a backup to the server.

7. Secure Architecture #3 – O&M Shared High Speed Connection

The architecture shown in Figure 5 adds a WAN connection to the substation shared between the Operations and Maintenance areas. In addition, the dial-up access exists as a backup to the

WAN based stations or as an example of a mixture of WAN and dial-up stations.

The O&M WAN connection changes method of access for both Operations (SCADA) and Maintenance access. Both are accessing the station using routable protocols and therefore both access methods fall in the NERC security requirement.

7.1 SCADA Access

SCADA access to the station would utilize a routable SCADA protocol such as DNP3, Modbus IP or IEC 61850. Cyber security for the SCADA system includes SSL using Secure Data Concentrator mode. The Secure Data Concentrator mode allows for SSL security to be applied to any routable SCADA protocols.

Obviously, this requires the security capabilities match for both the SCADA Master Station and the Gateway. Additionally both systems must recognize the other's certificate and SSL/TLS encryption.

7.2 Maintenance Access

The maintenance access is similar to the connection in the previous examples, User-ID with a strong password authentication and SSL with PKI. But now WAN based Gateways are accessed over the WAN eliminating the need for serial PPP. Serial PPP would only be used for substation without WAN connection or as a backup. The speed of the connection will be much faster and more reliable than dial-up.

Also, because both SCADA and Maintenance share the same WAN it would be useful if the WAN is designed to support prioritizing SCADA packet over Maintenance packets so that there is no impact on SCADA whenever large files are being copied to the Maintenance Server.

7.3 Remote access to IEDs

This system is similar to the previous option but provides a LAN connection to the Gateway. Utilizing Secure Connection Relay, the Server establishes the access control in the Gateway and enables/disables access as appropriate with these scripts. As with the previous architecture, the serial IEDs are accessed through serial tunneling software on the Server and Gateway and Ethernet IEDs. These methods restrict remote User access to only the IEDs that the User is authorized to access.

7.4 System Advantages

This architecture has similar advantages to the previous system and operates at LAN speeds. This provides a significant performance boost for User access.

By sharing the communications channel between the Operations and Non-Operations access, the costs providing two connections is reduced and the two connections can share the bandwidth and performance improvements of the higher speed line. It may be necessary to add the ability to prioritize the Operational traffic over the Non-Operational traffic in the LAN equipment connected to the communications channel.

This system has the advantages of supporting SSO and centralized access right control. Allowing user accounts to be administered in a single location.

7.5 System Disadvantages

Sharing the LAN connection to the Gateway by both Operations and Maintenance can increase the security risks. It is necessary to prevent unauthorized users from gaining access anything on the Dispatch Center. Often this system provides a Maintenance LAN connection that is physically restricted and not connected to the Corporate LAN, increasing security and reducing flexibility for various users.

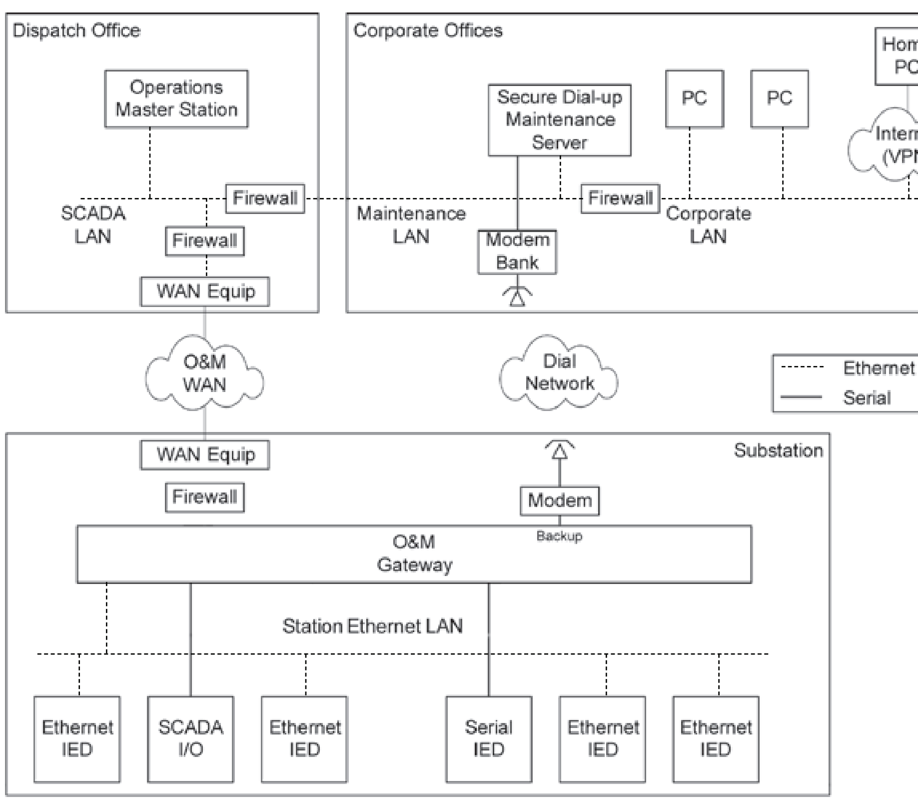

Fig 5.
Shared O&M WAN.

This system also requires users to have LAN access to the Maintenance Server before they can access the Gateways in the Station. Two-factor authentication is still required at the Maintenance Server.

If dial-up access is still necessary from multiple sites to the Gateway then both methods need to be administrated on the Gateway and Maintenance Server making the system more complicated. Administrators may desire to provide only a few authorized dial-up users to operate only as a backup to the server.

8. Secure Architecture #4 – Separate O&M High Speed Connection

This architecture is more popular than the previous architecture where the SCADA and Maintenance WANs are separated into two networks. This could be a completely separate communication channel or a part of a Virtual LAN or VLAN. A VLAN provides the capability for the WAN/LANs to coexist on the same physical network or network equipment. Otherwise, this system is identical to the functionality of the previous system.

8.1 Remote access to IEDs

This system is similar to the previous options but separates the two LAN connections to the Station. Often this connection is operated over the same physical connection using two Virtual LANs, or V-LANs. Equipment connected to each end of the communications channel separate the two V-LANs into two separate physical LANs at each end. Often, this equipment also allows the ability to dynamically assign channel bandwidth between the two V-LANs as necessary.

8.2 System Advantages

This architecture has similar advantages to the previous system and operates at LAN speeds with improved security because there is no connection to the Operations LAN from the Maintenance LAN.

By sharing the communications channel using V-LANs between the Operations and Non-Operations access, the costs can be reduced and the bandwidth can be shared while reducing the security risks.

This system has the advantages of supporting SSO and centralized access right control. Allowing user accounts to be administered in a single location.

8.3 System Disadvantages

This system also requires users to have LAN access to the Maintenance Server before they can access the Gateways in the Station. Two-factor authentication is still required at the Maintenance Server.

If dial-up access is still necessary from multiple sites to the Gateway then both methods need to be administrated on the Gateway and Maintenance Server making the system more complicated. Administrators may desire to provide only a few authorized dial-up users to operate only as a backup to the server.

9. Secure Architecture #5 – Separate Station and Corporate LANs

This architecture breaks the routable connections between the Maintenance LAN and the Corporate LAN or the Station LAN. This architecture is functionally identical to the system previously

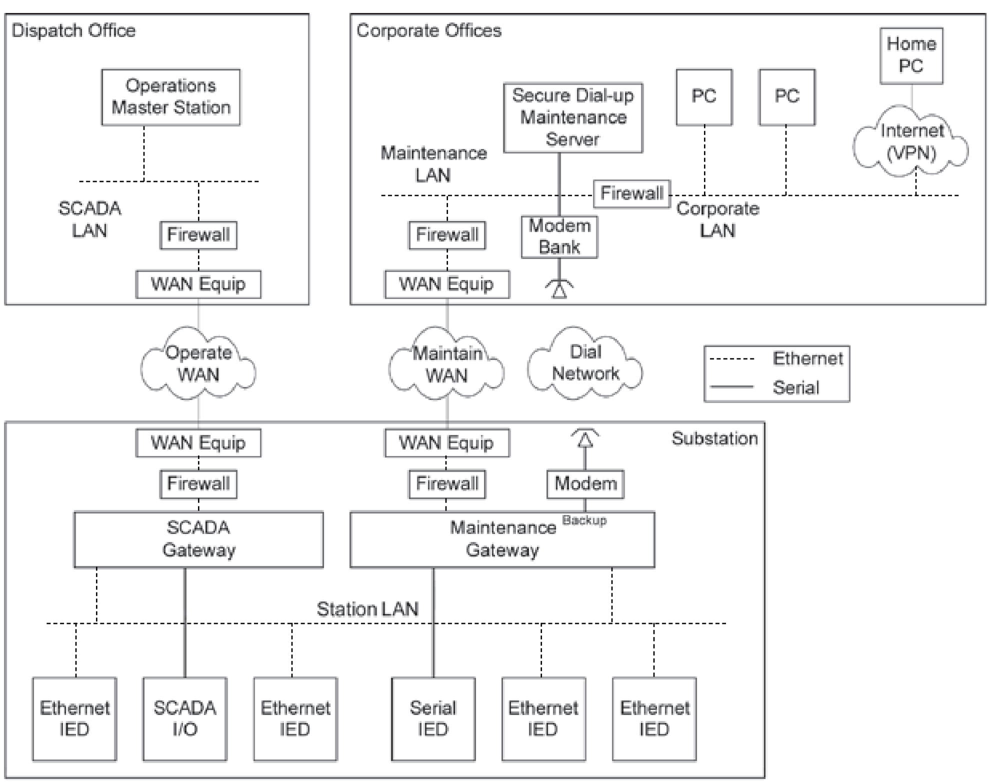

Fig 6.
Separate O&M WAN.

described however it provides an improved level of security and isolation of the various functions.

IEDs that need to share data with both the SCADA and the Maintenance Gateway must do so over a non-routable connection. Those IEDs must communicate over two communication channels or the two Gateways to share IED data serially between the Operations and the Maintenance Gateways. This breaks the routing connection between the two LANs in the substation completely.

The Corporate LAN is also disconnected from the Maintenance LAN. A new Maintenance Database Server is added to the system with two NIC cards. The Maintenance Server is designed not to create a routable connection between the two LANs. The Maintenance Gateway in the station will automatically send data and oscillography files to the Maintenance Database Server. Users on the Corporate LAN can access the substation data on the Maintenance Database Server without having a direct connection to the station. The Maintenance Server must be secured to prevent a Corporate LAN User from gaining access through to the Maintenance LAN.

Devices connected to the Dispatch Office side of the Maintenance LAN can access the Maintenance Gateway and with SSL and PKI can access the serial and Ethernet IEDs directly. Of the security architectures discussed here, this architecture is the most secure but can be the most complicated.

9.1 Remote access to IEDs

This system is similar to the previous options but separates the Maintenance LAN from the Corporate LAN. It also separates the Station Operations and Maintenance LANs. Access to the IEDs is only provided by users connected directly to the Maintenance LAN. Users on the Corporate LAN can access a new Maintenance Database Server which provides data from the Station IEDs and the Gateway without providing remote access from users outside the Maintenance LAN.

9.2 System Advantages

This system provides the greatest level of security between the Corporate LAN and the Maintenance LAN because there is no routable connection between the two LANs. User's can access data from the Stations on the Maintenance Server and can access the IEDs directly from the Maintenance LAN which is often only available in a physically secure location. Two-factor authentication is no longer required by the Corporate LAN Users because they cannot gain access to the Gateways directly from the Corporate LAN.

This system has the advantages of supporting SSO and centralized access right control. Allowing user accounts to be administered in a single location.

9.3 System Disadvantages

This system is more complicated and restricts remote access only to users who have LAN access to the Maintenance LAN before they can access the Gateways in the Station. Two-factor authentication is still required at the Maintenance Server for these users. This system also is more expensive and requires dual serial communications to the IEDs and/or a serial data connection between the SCADA and Maintenance Gateways.

If dial-up access is still necessary from multiple sites to the Gateway then both methods need to be administrated on the Gateway and Maintenance Server making the system more complicated. Administrators may desire to provide only a few authorized dial-up users to operate only as a backup to the server.

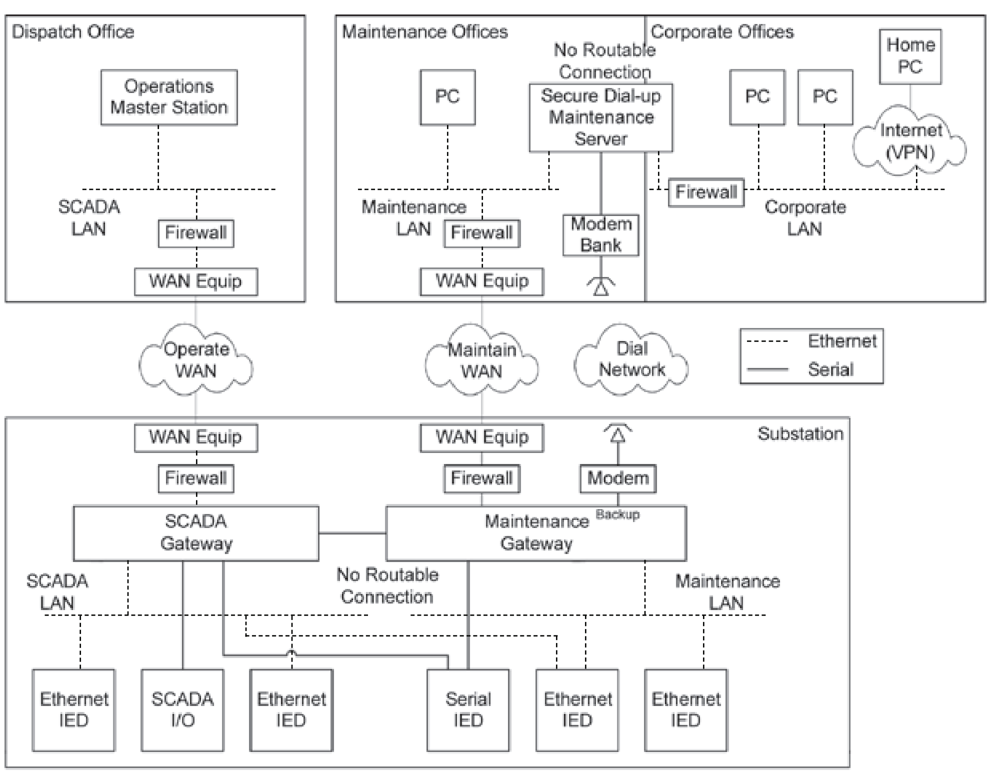

Fig 7.
Separate O&M Station LAN.

10. Summary

As utilities seek to balance the critical nature of the asset and the cyber threat with the access requirements of authorized Users, the search for solutions will continue to be an ongoing challenge for both Utilities and Security Solution Suppliers. Most Utilities are implementing a mix of the architectures outlined in this paper depending on the critical nature of the asset and the communications available to the site.

Answers to the following questions will help determine the architecture that fits best:

- what Users need access to the data from the IEDs and who needs direct access to the IEDs?
- what type of communications exists or is economically available?
- what type of substation architectures are implemented or planned? Do they include Ethernet?
- will the Maintenance LAN and Operations LAN be connected? At the Substation, share a communications line, or at the dispatch office?
- how will the Corporate LAN be connected to the system if at all?
- will authorized Users be able to access the data or the IEDs from remote locations?

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Enhanced Algorithm for Motor Rotor Broken Bar Detection

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1. Abstract

Motor rotor broken bar is one of the predominant failure modes of squirrel cage induction motors. There are numerous researched methods for identifying rotor bar faults: motor current signature analysis, acoustic noise measurements, vibration monitoring, temperature monitoring, electromagnetic field monitoring, infrared recognition, radio frequency emissions monitoring, etc. The most frequently used method is called the Motor Current Signature Analysis (MCSA). It is based on a signal analysis of the motor current, obtained via a regular current transformer used for motor protection purposes. It is difficult to detect rotor bar failures by looking into the currents waveform-time domain analysis, however impact of rotor broken bars to the stator currents can be determined by analyzing spectrum of frequency distribution in the frequency domain.

Many factors affect reliable detection of the motor broken bar; motor load, system frequency and motor speed, construction of the motor etc. A new algorithm takes into account all these factors to adapt to a changing operational condition of the motor. Also, by learning the healthy motor frequency spectrum signature, the detection of a broken rotor bar can be made even more deterministic.

The new algorithm was extensively tested on the induction motors with different system and motor conditions-results of this testing are presented. Lessons learned from the field installations are presented as well.

2. Introduction

Induction motors play an important role in the safe and efficient run in any industrial plant. The incipient fault detection or condition monitoring of the motors will help avoid expensive repairs or losses due to industrial process interruptions. Even though the motors are designed for a long fault-free time, usually 30 years, they are susceptible to failures and their sheer volume and high cost may result in an expensive maintenance. Various studies have shown that about 50 percent of motor failures are due to bearing failures, 35 percent due to insulation failures, 10 percent due to rotor cage failures, and 5 percent due to other causes [1].

This paper presents one method for an efficient detection of rotor related problems in a squirrel-cage induction motor.

3. Existing Methods

Numerous rotor failures detection methods have been proposed with a varying level of practicality and efficiency. Those methods often span several fields of science and technology. The most used methods for detecting the rotor bar problems are [2]:

- Motor current signature analysis (MCSA),
- Acoustic noise measurements,
- Model, artificial intelligence and neural network based techniques,

- Noise and vibration monitoring,
- Electromagnetic field monitoring using search coils, or coils wound around motor shafts (axial flux related detection),
- Temperature measurements,
- Infrared recognition,
- Radio frequency (RF) emissions monitoring,
- Chemical analysis, etc.

The major limitation of most methods is that they require involvement of costly experts, or costly equipment, or both. Some methods are prone to false alarms, and others are simply not practical for deployment in an industrial plant environment.

A PRACTICAL METHOD FOR DETECTION OF BROKEN ROTOR BARS BASED ON MOTOR CURRENT SIGNATURE ANALYSIS (MCSA)

Here, we present a practical method for detection of broken rotor bars, based on Motor Current Signature Analysis (MCSA) with no additional equipment needed beyond a motor protection relay, which is likely to be already present.

An ordinary MCSA detection algorithm is easy to implement and deploy. It needs one current transformer and a micro-controller capable of taking samples of one phase current and performing a Fast Fourier Transform (FFT). The decision algorithm is a different story. An expert (system) is needed to interpret the calculated level results; otherwise a false detection is inevitable.

3.1 Motor Current Signature Analysis (MCSA) Background

Under perfectly balanced conditions (source, motor and load) the stator phase currents are constant. For the purpose of analyzing rotor bar failures, it is sufficient to observe one phase current only, due to symmetry of a three-phase motor. A defect in a rotor bar of an induction motor causes the modulation of the stator current. This means that the current envelope will change according to the severity of the rotor failure. The current envelope is an imaginary curve connecting peaks of the phase current sinusoidal waveform.

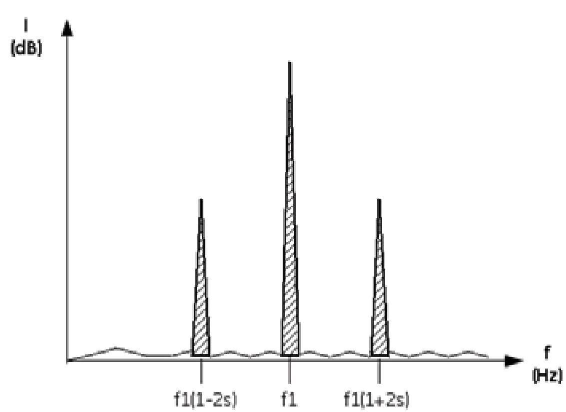

Figure 1.
Simplified broken rotor bar current spectrum

It is difficult to analyze characteristics of rotor bar failures by looking into the current waveform - time domain analysis. The impact of broken rotor bars to the stator current can be determined by analyzing in the frequency domain. This approach in detecting rotor bar failures is called a Motor Current Signature Analysis (MCSA).

Again, in perfectly balanced conditions, the stator current will be represented with a single spectral component in the current spectrum. It will be located at the frequency of the power source (i.e. 60 or 50 Hz, dependant on the power system). Let's label this frequency as "f1". When a rotor bar failure is present, additional spectral components will be present too. The following analysis will try to explain them. Normally, in a real life situation, there will be many other components of various amplitudes – source harmonics, noise, components due to other imperfections (bearing faults, presence of gear boxes or belt drives, periodic changes of the motor load), etc.

In order to place spectral components caused by rotor bar failures on the current spectrum, let's review an induction motor slip properties. In a healthy motor operating in balanced conditions, there is a forward rotating magnetic field produced by stator.

This field rotates at synchronous speed:

$$n_1 = f_1/p \qquad \text{Eq. 1}$$

where "f_1 " is the power source frequency and "p" is number of pole-pairs of the stator windings, per phase. The rotor of an induction motor always rotates at the speed "n", which is less than the synchronous speed "n_1". The slip is defined as:

$$s = \frac{(n_1 - n)}{n_1} \qquad \text{Eq. 2}$$

and it is a measure of how much the rotor slips back behind the rotating magnetic field.

The slip speed "n_2" is the actual difference between the speed of the rotating field and the actual speed of the rotor: $n_2 = n_1 - n$. If we multiply both sides of slip definition by n_1, we get $s \cdot n_1 = n_1 - n$. By replacing $(n_1 - n)$ with n_2 in the slip speed definition per equation 2 above, the slip speed becomes $n_2 = s \cdot n_1$.

The frequency of rotor current is called the slip frequency and it is defined as:

$$f_2 = n_2 \,.\, p = s \,.\, n_1 \,.\, p \qquad \text{Eq. 3}$$

The speed of the rotating magnetic field produced by the rotor bar current, with respect to the stationary stator winding is given by:

$$n + n_2 = n + n_1 - n = n_1 \qquad \text{Eq. 4}$$

This means that from the fixed stator perspective, the speed of the rotating magnetic field caused by the rotor is equal to the stator caused rotating magnetic field. Therefore, both magnetic fields rotate at the synchronous speed. They appear to be locked to each other, and they produce a steady torque.

When there are broken rotor bars in a motor, there will be an additional magnetic field present. This magnetic field rotates backwards at the slip speed with respect to the rotor. From stator point of view this magnetic field rotates at speed $n_b = n - n_2$. It was determined earlier that $n + n_2 = n_1$, or $n = n_1 - n_2$, and $n_2 = s \cdot n_1$. By substituting these values above, the n_b becomes:

$$n_b = (n_1 - n_2) - s \cdot n_1 = n_1 - s \cdot n_1 - s \cdot n_1 = n_1 - 2 \cdot s \cdot n_1 = n_1 \cdot (1 - 2 \cdot s)$$

Eq. 5

The equation above means that the stationary stator "sees" the rotating magnetic field due to broken rotor bars at the speed:

$$n_b = n_1 \cdot (1 - 2 \cdot s) \qquad \text{Eq. 6}$$

By dividing the left and right side by "p", and keeping in mind that $f_b = n_b / p$ and $f_1 = n_1 / p$, the equation describing the effect of broken rotor bars becomes:

$$f_b = f_1 \cdot (1 - 2 \cdot s) \qquad \text{Eq. 7}$$

The equation above is the fundamental equation of the algorithm, using the MCSA principle. The rotating magnetic field due to broken rotor bars induces the current in the stator windings at "f_b" frequency. In the stator current spectrum the component caused by broken rotor bars is located $2 \cdot s \cdot f_1$ down from f_1, which is the source frequency. The speed and torque oscillations occur at frequency $2 \cdot s \cdot f_1$, which means that there is a spectral component located at $f_1 + 2 \cdot s \cdot f_1$ as well. Therefore the spectral components due to broken rotor bars can be expressed as:

$$f_b = f_1 \cdot (1 \pm 2 \cdot s) \qquad \text{Eq. 8}$$

The lower component is due to broken bars, and the upper one is due to a related speed oscillation. Since the broken rotor bar disturbances are of an "impulse nature" (not a pure sine wave), the broken rotor bar spectral components can be expressed more accurately as:

$$f_b = f_1 \cdot (1 \pm 2 \cdot k \cdot s) \qquad \text{Eq. 9}$$

where k = 1, 2, 3...

The amplitude of harmonic spectral components due to rotor bar defects, where k >= 2, are dependant of the geometry of the fault. Their amplitude is significantly lower than the "main" sidebar component and they can be ignored in this analysis. It is sufficient to measure the ratio of amplitudes one of the "main" sideband components versus the amplitude of the source frequency component, in order to "judge" the effect of the rotor bar defects. This ratio is directly proportional to the failure severity (the number of cracked or broken rotor bars). The upper and lower "main" sideband components are equal and it is irrelevant which one is used for calculation of the ratio.

The position of sideband components, with respect to the source frequency component, is proportional to the motor slip. Due to frequency resolution of the detection method and presence of a source frequency "jitter", it may not be possible to detect sideband components while the motor is idling, or running at light loads, i.e. while the slip is very small and the sideband components are very close to the source frequency.

4. Field Experience with MCSA Based Fault Detection

The method described above was incorporated many years ago and has a field experience history. At one facility, with approximately 110 medium voltage motors, three (3) motors have been identified with broken rotor bars in the past 10 years. A motor with a broken rotor bar is usually detected by an operator who reports high motor noise or vibration, or during routine maintenance of the motor by using current signature analysis that checks the motor phase current sideband component frequency magnitude versus the fundamental frequency. The protective relay is used to provide confirmation that a motor has broken rotor bars. The suspect motor sideband value is compared to an identical motor under the same loading. The relay confirms that the suspect motor has a broken rotor bar when the magnitude of sideband current is higher.

The relay also provides a maximum value of percent sideband current. During a motor start the percent sideband current is very high and usually this value is recorded in the maximum value field.

But field experience prompted improvements in the next generation relays with a broken rotor bar detection, which should include the following:

- An alarm set point with an adjustable value.
- If frequency tracking is not implemented in the motor protective relay, then additional error is possible-therefore it's desirable to have a robust frequency tracking mechanism in the relay.
- Disable broken rotor bar detection readings during motor starting and load changes.
- Learn trends in motor slip frequency at different operating conditions, including different load, operating voltage, etc.
- Measure broken rotor bar component level in decibels to quantify probability of having this kind of motor failure.

The picture bellow is from a coal-fired power plant with three turbine generators. It shows the damaged rotor of a medium voltage motor, rated for 6600 V, 1500 HP, used as a primary air fan motor.

Figure 2.
6600 V, 1500 HP fan motor with broken rotor bars (field picture)

5. Algorithm Implementation Description

The implementation of the algorithm for detection of the rotor bar damage, based on the current signature analysis, as a standalone device caries many risks of a false detection. A human expert operator is usually employed, in order to minimize false detections. Since the standalone devices are not suitable for a continuous monitoring without a costly expert operator, damage to the rotor may go undetected for a period longer than necessary. Often the rotor damage is suspected only when the motor is slow to accelerate, or even cannot be started successfully.

IMPLEMENT BROKEN ROTOR BAR DETECTION ALGORITHMS & SUPERVISION CONDITIONS TO IDENTIFY ROTOR PROBLEMS EARLY & REDUCED FALSE ALARMS

The algorithm for detection rotor of bar damage, based on the motor current signature analysis, consists of a series of digital signal processing steps necessary for evaluating the current spectral components attributed to the presence of damaged rotor bars. These steps include signal sampling, digital filtering, Fast+ Fourier Transform, sample decimation, anti-aliasing filtering, etc. In order to work in a "non-operator assisted mode", this algorithm needs to be hardened with a series of measures to avoid false alarms.

In order to achieve a proper frequency resolution and accuracy a sample of motor current spanning at least 10 seconds is required for the relay sampling 64 samples per cycle. This results in 2048 length of FFT. A synchronous amplitude demodulation is applied before a series of up to 30 FFTs are performed. It takes approximately 30 seconds to acquire data and calculate the ratio of side-band component versus the fundamental. In the implementation discussed in this paper, the dynamic range of 65 dB, with accuracy of +/- 1.5 dB was achieved. This turned out to be sufficient, since the typical value of interest is in the range of –60 to –40 dB.

This conclusion is based on the published experimental data on the Broken Rotor Bar (BRB) spectral component level, relative to the fundamental level. It indicated that [5]:

- If the BRB component level is around –60 dB or more, there is probably, no fault.
- If the BBR component level is at least at –54 dB, there is, very likely, a cracked rotor bar.
- If the BRB component level is greater than –50 dB, there is probably a broken bar.

The implementation of the broken rotor bar detection algorithm in a motor protection device, and equipping it with necessary supervision conditions readily available in a motor protection device, which allows early detection of the rotor problems with substantially reduced risk of false alarms.

The current signature analysis method requires a relatively long data set in order to provide a sufficient frequency resolution that is necessary for accurate fault detection. This data set is approximately 10 seconds long. During that period various disturbances can create a false detection scenarios. The following text enumerates those conditions and describes a practical solution for each of them.

System Frequency Deviation from Nominal

The frequency deviation from a nominal value is a major risk for a false detection since the applied algorithm uses a synchronous envelope demodulation.

This issue is being resolved by employing a frequency-tracking algorithm, normally used on an advanced protection device for accurate phasor components calculations. The frequency-tracking algorithm plays a role in the carrier frequency recovery - the essential step for synchronous demodulation accuracy.

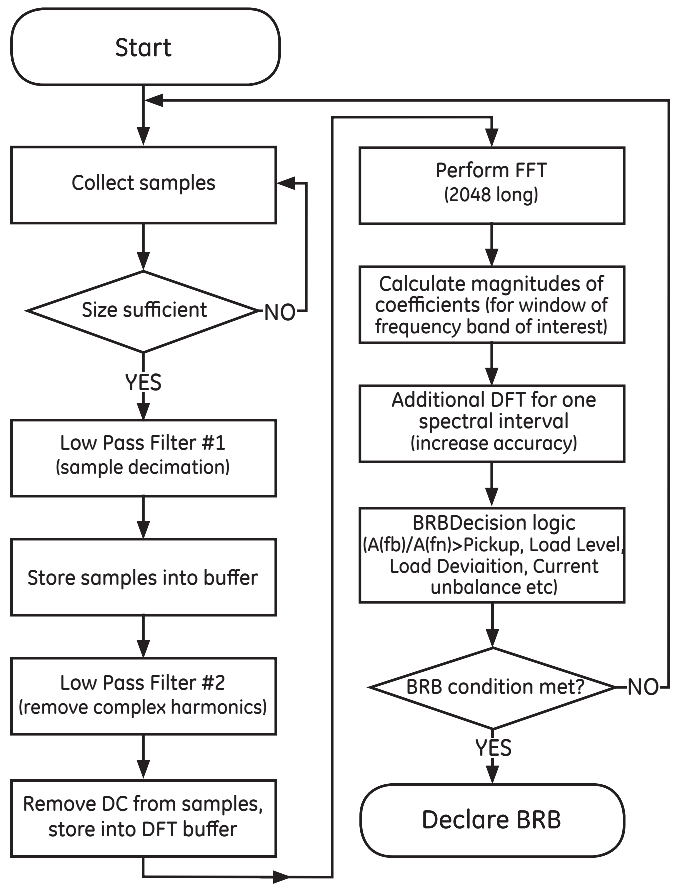

Figure 3.
Flowchart of algorithm processing

5.1 Motor Load Variation

The load variation could be the source for a false detection of a spectral component attributed to a damaged rotor bar. Knowing or estimating the motor slip can result in a narrower window where the broken rotor bar component may reside, effectively reducing probability of a false detection. Even better results are achieved by monitoring the motor load variations during the data acquisition algorithm. The motor load is readily available on a motor protection device for other purposes. For the supervision of the detection algorithm for rotor bar faults, it is sufficient to calculate the standard deviation of the motor load every several power cycles. If the standard deviation of the motor load exceeds a preset value, the data set is discarded and the data acquisition starts from the beginning. The algorithm will effectively search and find an interval of a steady motor load required for the detection of rotor damage.

5.2 Motor Current Unbalance

An unbalance power source, or internal unbalances in the motor itself, will cause causing the motor current unbalance. The current unbalance can possibly impact the broken bar algorithm results. Since the current unbalance is readily monitored on a modern protection device, the broken bar algorithm is blocked when the current unbalance crosses a preset value. This value should be set somewhat below the level for the current unbalance alarm.

5.3 Motor Starting and Overloaded Condition

The motor start phase and any overload situation are also excluded from the broken rotor bar detection based on the motor load level. This is in order to eliminate any possibility of a changing motor current having the spectral components in the window of interest for the broken rotor bar detection.

5.4 Dynamic Measuring Range

A protection device metering system is normally designed to handle medium and high signal levels necessary for protection functions. The metering of very small values, associated with the broken rotor bar, is compromised when the motor is lightly loaded. For that reason the broken rotor bar detection is blocked while the motor load is below a preset value. In addition to that, a sliding window based filter is applied to the calculated spectral components in order to further reduce the likelihood of a false alarm.

5.5 Broken Rotor Bar Components Dependency on Motor Load Level

The practical measurements of the current spectral components attributed to the damaged rotor bars are somewhat proportional to the motor load level, even though the theoretical values are not. In order to prevent a false alarm for higher load levels, a simple restraining algorithm is applied. This restraining algorithm dynamically modifies the rotor bar alarm level based on the motor load level at the time of measurement.

5.6 Delay in Declaring Rotor Damage Alarm

The slow progressing rotor damage does not require an instantaneous response. As a final step in the prevention of a false detection, a delay of an arbitrary length is applied to the decision-making. The alarm level has to be present for a preset time before the alarm is actually declared. This step helps filtering out any false detection not being caught by other supervision measures.

6. Test Results and Analysis

Various lab tests on a 3 kW induction motor, under different load conditions (hence different slip) and with different number of rotor broken bars, are carried out to validate the described algorithm and to check the performance of the motor BRB detection function in the relay.

Figure 4.
Lab testing of the new algorithm

6.1 Fault Sensitivity Test

This test is performed to measure the sideband component levels for different degrees of rotor broken bars at a given load condition. The component level is expected to increase with the severity of rotor broken bar. The experiment result may be used to set the minimum pick up level for the algorithm to indicate the presence of the broken bar in the rotor so as to avoid any false alarms.

Test Procedure:

a) The load on the motor is kept constant.

b) The rotor broken bar frequency is estimated based on the supply frequency and rotor speed for the given load.

c) Start of BRB sideband and end of BRB sideband is set such that the estimated BRB frequency is within the band.

d) For different rotors namely healthy, 1 broken bar, 2 broken bars and 3 broken bars, the component level and component frequency is tabulated as below.

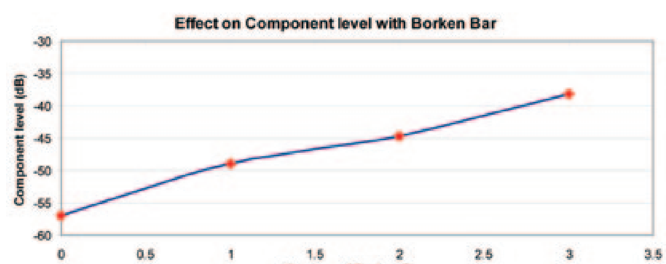

Figure 5.
Relationship between number of broken bars and component levels

Rotor Case	Supply Frequency (Hz)	Load FLA	Rotor Speed	Estimated BRB frequency (Hz)	Start of BRB sideband (Hz)	End of BRB sideband (Hz)	Component Level (dB) (averaged value)	Component Frequency (Hz)
Healthy	49.13	0.81	1456	47.93	-1.63	-0.63	-57.04	47.77 to 47.96
1BRB	48.6	0.78	1446	47.74	-1.66	-0.66	-48.89	47.54 to 47.65
2BRB	49.2	0.78	1460	48.13	-1.7	-0.7	-44.7	48.13 to 48.2
3BRB	49.5	0.79	1467	48.3	-1.5	-0.5	-38.23	47.95 to 48.28

Table 1.
Component levels change for different number of broken bars

The test result clearly indicates that the sideband component level increases as the number of broken rotor bars increases. The minimum pickup level can be set between –55 and –50 dB for this motor.

6.2 Sweeping Frequency Test

This test is performed to determine the effect of sweeping the frequency window setting on the component level measured at a given load for a constant degree of rotor broken bars failure.

Test Procedure:

a) The load on the motor is kept constant.

b) The rotor broken bar frequency is estimated based on supply frequency and rotor speed for the given load.

c) For a given rotor fault, the start of BRB sidebands and end of BRB sidebands are swept with a given width of 1Hz.

d) The actual parameters for each test are recorded in the table below.

Number of BRB	Load (FLA)	Sweeping Frequency Window Width (Hz)	Supply Frequency (Hz)	Motor Speed (RPM)	Estimated BRB Frequency (Hz)
Health	0.9	1	49.03	1430	46.3
1	0.89	1	49.05	1430	46.28
2	0.89	1	49.35	1445	46.98
3	0.91	1	49.15	1436	46.58

Table 2.
Sweeping frequency test

e) The component level versus sweeping frequency at different fault levels is plotted as below

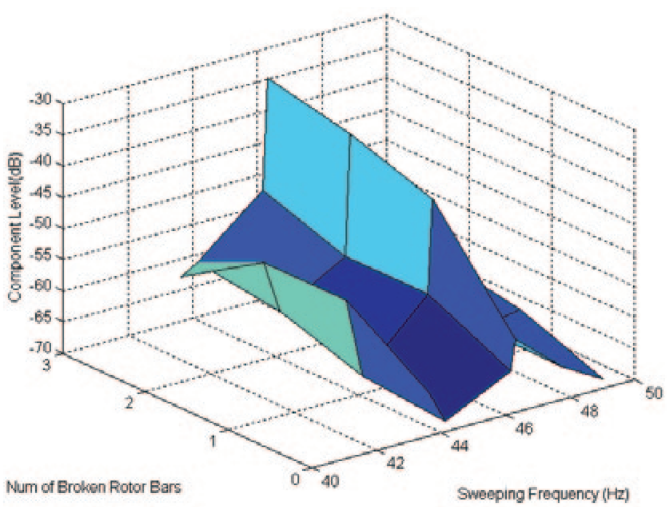

Figure 6.
Sweeping frequency test illustration

It can be seen from this plot that the component level reaches the maximum value when the sweeping frequency window reaches the estimated sideband component frequency, $f_b = (1 - 2 \cdot s) \cdot f_1$.

6.3 Effect on Steady Load

This test is performed to determine the effect of load on the component level measured for a constant degree of rotor broken bars failure. It is known that the component frequency of the rotor broken bar signal is slip dependent. Now, whenever there is a rotor with a broken bar in the induction machine, the algorithm may not indicate its presence because of the very low slip under no load conditions. This experiment aims at determining the minimum load required so that the algorithm can detect the fault.

Test Procedure:

a) The width of the sideband window is kept constant for a given rotor fault.

b) The load on the motor is varied.

c) For each load on the motor, the rotor broken bar frequency is estimated based on the supply frequency and rotor speed.

d) The start of BRB sidebands and end of BRB sidebands are set according to the estimated rotor broken bar frequency.

e) The component level and component frequency is plotted as below.

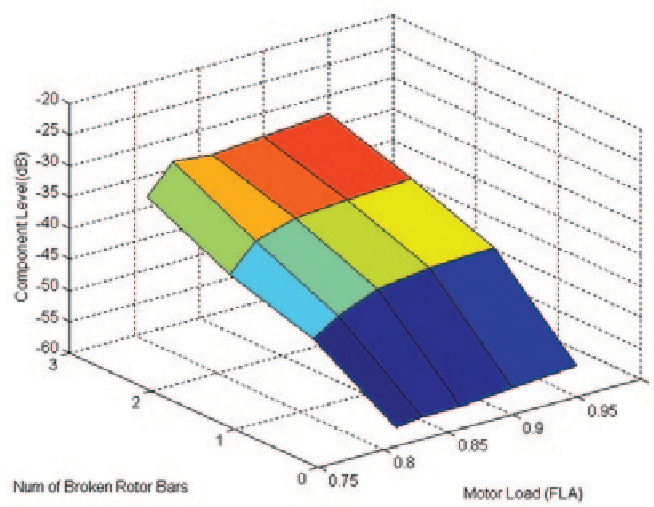

Figure 7.
Steady load frequency test illustration

It can be seen that the measured sideband component level decreases as the load decreases. For the test we have carried out in the lab, i.e. the load varied from 0.78-0.99 FLA, the BRB component level was discriminative to detect the BRB condition.

6.4 Offline FFT Analysis on Captured Waveforms

Some current waveforms have been captured during the test and the frequency spectrums of these waveforms were analyzed offline using FFT to compare with the online measurement of the sideband components.

One of these waveforms is shown below, in which the motor load was 0.97FLA, supplied frequency was 49.1 Hz, motor speed was 1427 rpm and with 3 rotor bars broken.

It can be seen that the current waveform amplitude was clearly modulated with an approximate 3 Hz signal. Based on the MCSA theory, the modulated signal frequency can be calculated as below:

$$slip = \frac{49.1 \times 30 - 1427}{49.1 \times 30} = 0.031228747 \qquad \text{Eq. 10}$$

The sideband frequency = (1-2*0.031228747)*49.1 =46.03Hz. So the modulated signal frequency was 49.1-46.03=3.07 Hz, which agrees with what we have observed from the current waveform.

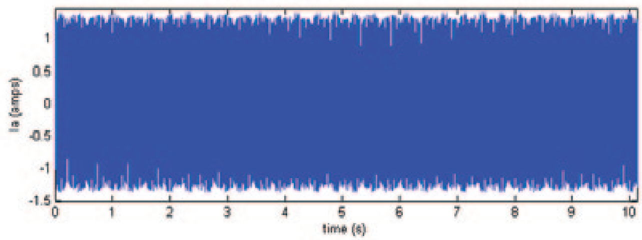

Figure 8.
Captured waveform for FFT analysis

The frequency spectrum of this captured current waveform from FFT is shown in the following figure. The sideband component frequency and the sideband component level from the offline FFT is 46.09 Hz and –35.17 dB respectively. This is very close to the online measurement values: 46.09 to 46.17 Hz and –33.68 dB.

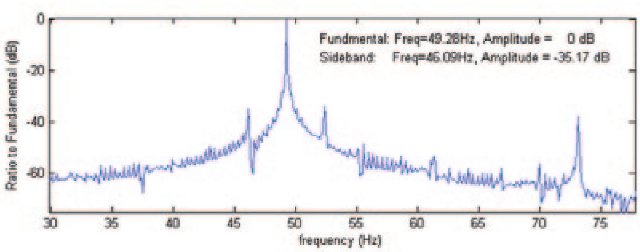

Figure 9.
Result of off-line FFT analysis

In summary, various tests have been performed with different levels of faults and different load level on the motor, the component levels and the corresponding component frequencies shown by the relay are observed which are in accordance with the expected values as per the theory.

7. Setting Example

This section explains which typical settings are required in a motor protective relay to accomplish a motor broken bar detection and how these setting are selected.

Start of BRB Offset

This setting defines the beginning of the frequency range where the spectral component due to a rotor bar failure, will be searched. The beginning of the frequency range is defined as:

$f_{start} = f_1 + f_{start\_offset}$

where "f_1" is system frequency, and "f_{start_offset}" is this setting.

If the upper sideband is to be measured, this setting should be set to a value equal to:

$f_{start\_offset} = 2 \cdot s \cdot f_1 - \max(0.3, \min(2 \cdot s \cdot f_1 - 0.4, 1.0))$,

where "f_1" is system frequency, "s" is the motor slip at full load, and 0.3, 0.4 and 1.0 are fixed values; "max" returns the largest of its arguments and "min" returns the smallest of its arguments. For example, if the full load slip is 0.01, set this setting to:

$2 \cdot 0.01 \cdot 60 - 0.8 = 0.40$ Hz, for a 60 Hz power system.

If the lower sideband is to be measured, this setting should be set to a value equal to:

$f_{start\_offset} = -2 \cdot s \cdot f_1 - \max(0.3, \min(2 \cdot s \cdot f_1 - 0.4, 1.0))$.

Using the same values from previous example, this value should be set to –1.2 - 0.8 = -2.00 Hz.

End of BRB Offset

This setting defines the end of the frequency range where the spectral component due to a rotor bar failure, will be searched. The end of the frequency range is defined as:

$f_{end} = f_1 + f_{end\_offset}$,

where "f_1" is system frequency, and "f_{end_offset}" is this setting.

If the upper sideband is to be measured, this setting should be set to a value equal to:

$f_{end\_offset} = 2 \cdot s \cdot f_1 - \max(0.3, \min(2 \cdot s \cdot f_1 - 0.4, 1.0))$,

where "f_1" is system frequency, "s" is the motor slip at full load, "max" returns the largest of its arguments and "min" returns the smallest of its arguments. For example, if the full load slip is 0.01, set this setting to: $2 \cdot 0.01 \cdot 60 + 0.8 = 2.00$ Hz, for a 60 Hz power system.

If the lower sideband is to be measured, this setting should be set to a value equal to:

$f_{end\_offset} = -2 \cdot s \cdot f_1 - \max(0.3, \min(2 \cdot s \cdot f_1 - 0.4, 1.0))$.

Using the same values from previous example, this value should be set to –1.2 +0.8 = -0.40 Hz.

BRB Start Block Delay

This setting is used to block Broken Rotor Bar detection function for a time defined by this setting, when motor is starting. This element is active only when the motor is running and will be blocked upon the initiation of a motor start for a period of time defined by this setting. For example, set it to 60 seconds to avoid false alarm during motor starting.

Minimum Motor Load

This setting is used to block the data acquisition of the Broken Rotor Bar detection function, as log as the motor load is below this setting. The Broken Rotor Bar detection algorithm cannot accurately determine the BRB spectral component when a motor is lightly loaded. For example, set it to 0.7 FLA.

Maximum Load Deviation

This setting is used to block the data acquisition of the Broken Rotor Bar detection function, as log as the standard deviation of the motor load is above this setting. The Broken Rotor Bar detection algorithm cannot accurately determine the BRB spectral component when the motor load varies. For example, set it to 0.1 FLA.

Maximum Current Unbalance

This setting is used to block the data acquisition of the Broken Rotor Bar detection function, as log as the current unbalance is above this setting. The Broken Rotor Bar detection algorithm cannot accurately determine the BRB spectral component in a current unbalance situation. For example, set it to 15% unbalance level.

Broken Rotor Bar Pickup

This setting specifies a pickup threshold for this element. The pickup threshold should normally be set to a level between –54 dB (very likely, a cracked rotor bar) and –50 dB (probably a broken rotor bar). For example, set it to –52 dB.

BRB Block

This setting specifies an operand blocking this function. Typically, a panel cut-off switch or other user specified conditions blocks this function.

8. Conclusions

This paper describes an algorithm for detection of broken rotor bars based on Motor Current Signature Analysis (MCSA) enhanced with a set of motor conditions, collected by a protection relay in order to avoid a false declaration of an alarm due to rotor problems. This approach greatly reduces a need for a human expert involvement in the results interpretation and the decision making process.

The proposed algorithm is implemented in a motor protection relay, and extensively tested for consistency and accuracy of alarms due to damage of rotor bars of an induction motor, both in simulated environment and in the electrical machine lab, involving real motors with various degree of rotor damage. The test results prove that the algorithm is capable of detecting abnormalities in the motor early, before they turn into expensive-to-repair failures. This algorithm detects problems of the rotor while the motor is online. Based on an alarm from this algorithm, it may be possible to prevent problems on the next motor start, for example, by scheduling maintenance at a more convenient time, or providing a backup motor. A more severe rotor bar fault may result in a significant torque reduction while the motor is starting next time, and an overload element trip at that time, may be significantly costlier to the process. The presence of broken rotor bars causes torque and speed oscillations in the rotor, provoking premature wear of bearings and other driven components. There is also a possibility of turning a non-detected rotor bar breakage into a catastrophic stator failure.

The future studies will include further enhancements in order to increase algorithm's robustness in case of pulsating motor load conditions.

9. References

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Reducing Arc Flash Risk with the Application of Protective Relays

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1. Abstract

The exposure to an arc flash high incident energy fault to technicians operating low and medium voltage switching equipment is a daily hazard in the workplace and there is an opportunity to improve safety. While PPE protects for first and second degrees burns it does not provide sufficient protection for the impact and forces that a high incident energy arcing fault produces and the gases released. One solution is to reduce the incident energy of the arcing fault.

This paper analyzes methods to reduce the exposure of personnel to high-energy arcing faults, and also defines a method to determine the limits of coordination among protective devices to identify where the selectivity could be jeopardized.

2. Introduction

Extensive studies on arc flash phenomena have been developed since Ralph Lee introduced the Arc Flash as a hazard in the work place [1]. This paper acknowledges these works and introduces awareness to mitigate the effects of the Arc Flash Hazard (AFH) by utilizing modern technology offered in protective relays, as well as to maximize the utilization of existing relays installed in electrical substations.

NFPA 70E [3] defines flash hazard as a dangerous condition associated with the release of energy caused by an electric arc. An Arc Flash (AF) is the result of a short circuit where the fault current is traveling through ionized air. The air provides a higher resistance path to the conduction of electricity and for this reason the resultant current flow could be as low as 43% of the bolted threephase short circuit fault on 480 V buses. The resultant intense heat, flying debris or shrapnel, projected molten cooper and gases released from an arcing fault produces a great amount of arc flash byproduct. The heat produced is calculated in cal/cm² and there are no methods to calculate the amount of shrapnel and molten material and gases released at the arcing spot.

The methods developed to calculate the incident energy generated by an arcing fault and the testing data acquired in controlled testing environments, indicates that the faster the fault is cleared, the less the caloric energy that is produced, consequently, the less molten material, shrapnel, and gases released.

Analyzing the settings of existing relaying systems and applying the multiple protection, control, and communication functions of modern protection relays provide implementation solutions of an electrical arc flash safety program in industrial facilities.

In a Petrochemical facility there are two electrical operating modes in a typical workday: Normal Mode and Switching Mode. The content of this paper is developed around these two scenarios, which are defined as follow:

Normal Mode: The normal operating mode is when the power equipment is energized and the load is being served to the production process units with no human interactions. If a non-arcing fault occurs, the protective equipment detects the fault and disconnects the faulted equipment very quickly and safely since there is no arc to damage the equipment. Conversely, if an arcing fault occurs, the protective relaying and other protective equipment should detect the fault but the current flowing will be less than the non-arcing fault and the time to clear the fault could be longer depending on the calculated settings and the equipment installed. The settings of protective relays and the selection of other protection equipment, such as medium and low voltage fuses and low voltage circuit breakers, should be set to minimize the incident energy to a lowest caloric value possible without jeopardizing selectivity.

Switching Mode: The switching operation mode is defined as when personnel execute electrical switching procedures to disconnect loads or to restore power to equipment that was previously disconnected for maintenance or repairs. During this mode of operation, the protection relays settings and the installed fuses and low voltage breakers combine to determine the fault clearing time and the level of incident energy developed if an arcing fault should occur. During switching activities of the power system, the personnel performing maintenance or modifications around energized equipment will be exposed to the dangers of an arcing fault, and the safety of the personnel takes priority over the selectivity of the protection apparatus. This protective apparatus must be set to ensure the reduction of incident energy levels by tripping the up stream breakers very quickly in order to reduce the fault clearing time.

Recognizing the different activities that substation personnel and other employees execute around energized equipment is the first step toward a safer environment, because it allows the identification of potentially dangerous actions that favor the development of arc flash faults.

3. Power System Analysis and Arc Flash Study Parameters

The plant's power system were the arc flash study was executed consists of a 138 KV ring formed by the utility feed and three large substations (figure 1). These substations transform the 138 KV system to 13.8 KV and 34.5 KV networks. The plant has a maximum load of 220 MW, which is fed from a 700 MW generating plant located just outside the plant's property. Some of the Medium Voltage (MV) switchgears are located in these large substations and cables runs on cable trays interconnect four satellite MV substations. The MV switchgear is equipped with a Main-Tie-Main (M-T-M) breaker configuration. The 480 Volt distribution substations are located throughout the plant and also have the M-T-M breaker configuration on the 480-volt side.

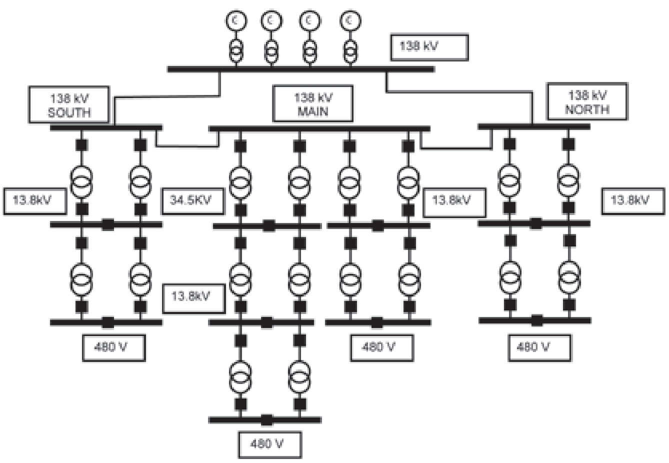

Figure 1.
Simplified one line drawing

Once the operating modes are defined, it will be necessary to identify what is considered a normal operating condition of the power system. The following conditions were defined as normal for the this industrial plant:

1. The power system is normally run with the tie circuit breakers open, except during switching operations. During switching operations, the tie breakers are closed which creates a higher arc flash level and AF labels were designed to indicate this condition.

2. Identify the transformers and buses equipped with differential protection and establish the protection operating times.

3. AF software settings. The software utilized to run the AF study included the following conditions:

    a. The AF calculation method utilized is IEEE-1584-2002 [1].

    b. The maximum fault clearing time is 2 seconds.

    c. The upstream device always clears an arcing fault.

    d. The coordination limits are based on IEEE-1584 for opening times of the circuit breakers (ref. table 1 on IEEE-1584 std.) and the breakers at the plant are periodically tested for compliance.

RECOGNIZING THE DIFFERENT ACTIVITIES THAT SUBSTATION PERSONNEL AND OTHER EMPLOYEES EXECUTE AROUND ENERGIZED EQUIPMENT IS THE FIRST STEP TOWARD A SAFER ENVIRONMENT

4. Selecting Coordination Time Intervals

The factors that can be controlled are in the time-current characteristics of the system protective devices through selecting different curves and settings to reduce the time to clear the arcing fault. These factors include:

- Pickup: the minimum current at which a device actuates. Lower pickup provides arc fault protection for a greater range of fault currents. The pickup should be selected based on the capacity of the equipment installed. The current transformer ratios must also match these capacities in order to optimize the relay settings for arc flash protection.

- Time delay. Shorter time delay reduces time to trip and lowers I^2t.

- Instantaneous pickup. Operating time is typically the minimum possible for the circuit being protected. Lower instantaneous pickup settings reduce arc flash hazard.

Coordination Time Intervals: Tightening up coordination time intervals is a direct and simple way of reducing tripping times and thus reducing t for any given I. Most engineers and many software programs use a 0.3-s minimum coordination time interval between tripping characteristics of series-overcurrent devices. While coordination margins can be securely reduced to 0.25 sec [4] when using digital protective devices, lower margins are acceptable if very specific testing and analysis are performed. In an effort to reduce the coordination time intervals, the operating times of protective relays are periodically tested and the records demonstrate that the tolerances found are per manufacturers instructions manuals. Chart 1 summarizes the circuit breaker (CB) clearing times and relays operating tolerances that were used to determine the coordination interval for reducing arc flash incident energy.

	CB Opening Time in ms	OC Relays Time tolerance in %
LV breakers (integral trip or external relay)	Mfg. Spec: 45 Tested Avg.: 50	
MV breakers	Mfg. Spec: 83 Tested Avg.: 83	
Electromechanical relays		+/- 5
Electronic relays		+/- 3

Chart 1.
Protective equipment operating times

Based on Chart 1 above, the following coordination Time limit is set:

LV and MV systems (480 v thru 34.5 KV): 200 ms

On LV systems the coordination time interval on the fast side is calculated as:

Coordination Time Interval (LV) = (200*0.97) – (50*1.03) = 142 ms

On MV systems the coordination time interval on the fast side is calculated as:

Coordination Time interval (MV) = (200*0.97) - (83*1.03) = 108 ms

If a lockout relay (86) is used in the operation of the protective relay and the tripping of the circuit breaker control logic a time of 8.5 ms must be subtracted from the above calculations.

As shown here, there is more than 100 ms of coordination interval on both voltage levels and the 200 ms coordination time will be used in new calculations to reduce the AF incident energy.

5. Short Circuit Study

To achieve selective coordination it is necessary to understand how the protection devices operate and how the short circuit currents decreases when the short circuit involves the air as the fault media. For the analyzed case, the short circuit and arc-flash current results, consisting of 2000 buses, are summarized in Chart No 2.

Voltage	# Of Buses	AF current in % of bolted Short Circuit span
34.5 KV	54	0
13.8 KV	814	80 -100
5 KV	27	82 -97
480 V	1080	43 - 94

Chart 2.
Short circuit levels

As shown on Chart 2 the LV buses experience the highest reduction of the short circuit current during an arcing fault and the protective apparatus must react to disconnect the faulted equipment during these reduced current conditions.

In order to maintain selective coordination the power systems engineer must update the arc flash calculations when the power system changes, e.g. when old transformers are replaced for equipment with higher capacities or if new loads are added to the existing system. The engineer must also ensure that the protective equipment is calibrated and circuit breakers and switchgears are properly maintained.

6. Normal Operation Mode – Original AF Results

The one line drawing on Figure 2 illustrates the typical AF incident energies that were found with the original settings calculated before the AF phenomena was introduced, chart 3 shows the data in tabular form and figure 3 the protective coordination for the same switchgear. Note the following aspects of the analysis:

1. The working distances was defined as 24 inches for 480 volts switchgear as per IEEE-1584 table 3, and 18 inches for shallow panels with bolt on covers such as the ones found on busducts and junction boxes on the secondary side of MV/LV transformers.
2. The tie breaker is normally open.
3. The AF on the secondary side of the transformer is 142 cal/cm²; this AF energy would destroy the busduct and would cause extensive damage to the transformer if an arcing fault occurs.
4. The AF on the line side of the circuit breaker is 136 cal/cm², this AF applies to the complete switchgear since an arcing fault occurring on the line side of the main breaker would cause extensive damage to the switchgear and would seriously hurt any personnel located around the gear.
5. Figure 4 shows the AF levels for an arcing fault if the tie breaker is closed, which is the case when personnel is executing switching operations for maintenance purposes. This is the worst AF condition and when the presence of personnel around the equipment is most likely to occur.

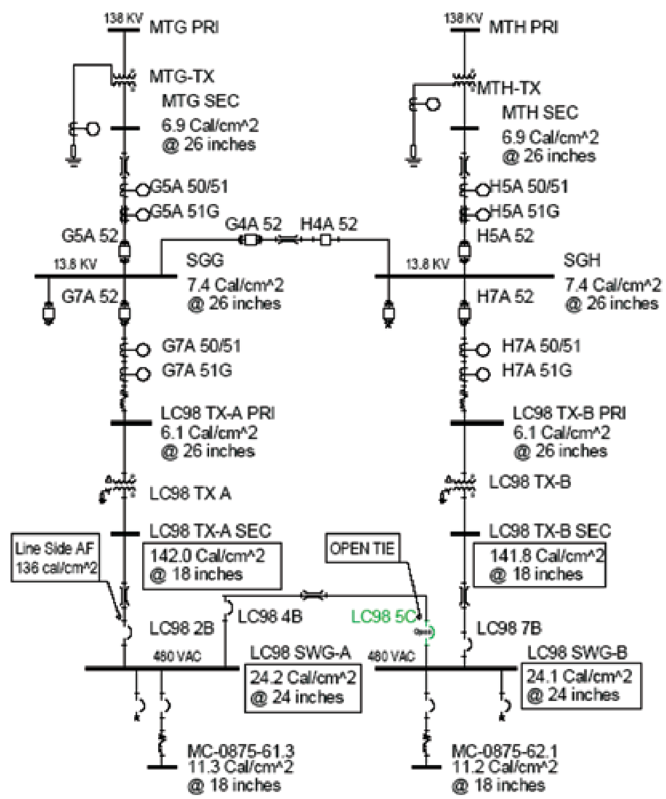

Figure 2.
Typical one line diagram. Open ties operation with AF levels as found

Bus Name 480 V	Protective Device Name	Bus Bolted Fault (KA)	Prot. Dev. Bolted Fault (KA)	Prot. Dev. Arcing Fault (KA)	Trip/ Delay Time (sec)	Brkr Opening Time (sec)	Incident Energy (cal/cm^2)
LC98 SWG-A (LC98 2B LINE SIDE)	G7A 50/51	30.9	29.5	15.4	1.91	0.050	136
LC98 SWG-B (LC98 7B LINE SIDE)	H7A 50/51	29.5	29.5	15.5	1.91	0.050	136
LC98 TX-A SEC	G7A 50/51	32.9	31.5	16.3	1.91	0.080	142
LC98 TX-B SEC	LC98 2B	31.5	31.5	16.4	1.91	0.080	142
LC98 SWG-A	G7A 50/51	30.9	29.5	15.3	0.5	0.080	24
LC98 SWG-B	LC98 7B	29.5	29.5	15.5	0.5	0.080	24

Chart 3.
Typical AF results for the one line shown in Figure 2

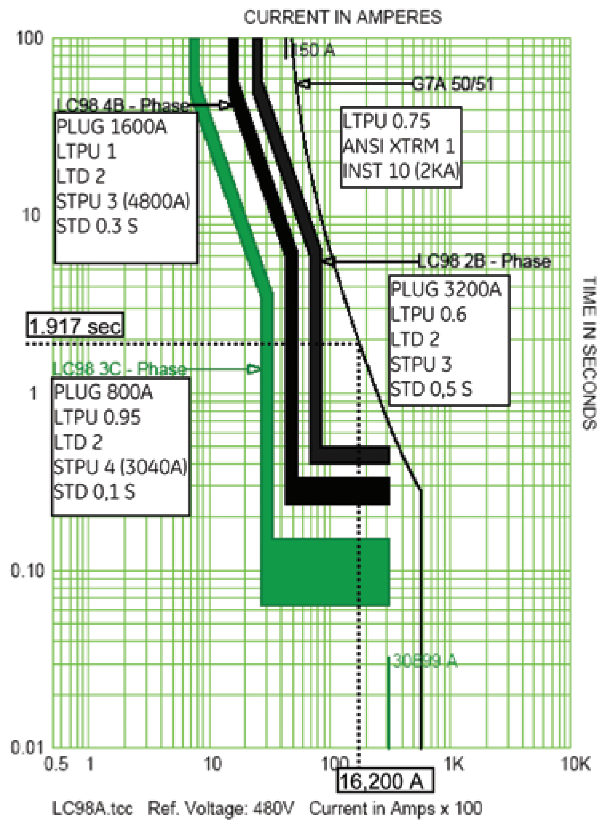

Figure 3.
Coordination chart for the one line diagram shown in Figure 2

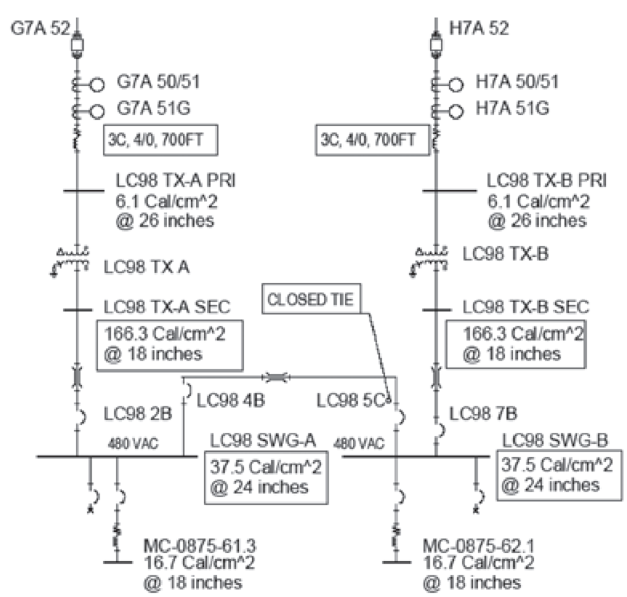

Figure 4.
Closed tie operation. Original AF levels

7. Reducing AF Incident Energy in Normal Operation Mode

As shown in the coordination charts, the LV circuit breakers have the protection unit integrated in the CB assembly and manufacturers provides a current-time characteristic that indicates the time when the main contacts start to open and the final time when the contacts had cleared the fault, on the other hand, the manufacturers of protective relays do not include the circuit breaker operating time since these relays can be used in a variety of circuit breakers. The AF software databases are built with all of these data already programmed and ready to use. In addition, the protection engineer may add relays and breakers not originally included in the database, such is the case of custom curves that the user can implement on modern microprocessor based relays.

In the case of protective relays, where the current-time curve is shown with a single line, the protection engineer must keep in mind the circuit breaker opening time in order to assure coordination during non-arcing faults.

The relays and circuit breakers analyzed in the example above were installed several years ago and they include electronic modules where a versatile set of current-time curves was available. The following conditions were set in order to reduce the arc flash energy during the normal operating conditions of the power system:

1. The coordination time interval was set at 200 msec.

2. Knowing that the power system operates with the tie breakers normally open, the protection settings of the tie and the main breakers can be matched since the tie breaker is closed during switching operation only and is when the maximum safety is required.

3. Set the short time pick up as low as possible in order to maximize the short time delay and to be able to trip quickly on low current arcing faults. Special attention must be given to the inrush currents of large motors connected to MCC's downstream.

The coordination chart on Figure 5 illustrate the new protective device settings, figure 6 is the one line drawing that shows the new AF levels and chart 4 is the tabular output of the AF software and it shows the short circuit currents and timing of the relays to clear the fault.

Bus Name	Protective Device Name	Bus Bolted Fault (KA)	Prot. Dev. Bolted Fault (KA)	Prot. Dev. Arcing Fault (KA)	Trip/ Delay Time (sec)	Brkr Opening Time (sec)	Incident Energy (cal/cm^2)
LC98 SWG-A	LC98 2B	30.4	29.5	15.4	0.335	0.050	17
LC98 SWG-B	LC98 7B	29.5	29.5	15.5	0.335	0.050	17
LC98 TX-A SEC	G7A 50/51	32.4	31.5	16.3	0.5	0.080	41
LC98 TX-B SEC	H7A 50/51	31.5	31.5	16.4	0.5	0.080	41

Chart 4.
AF report with reduced incident energy levels

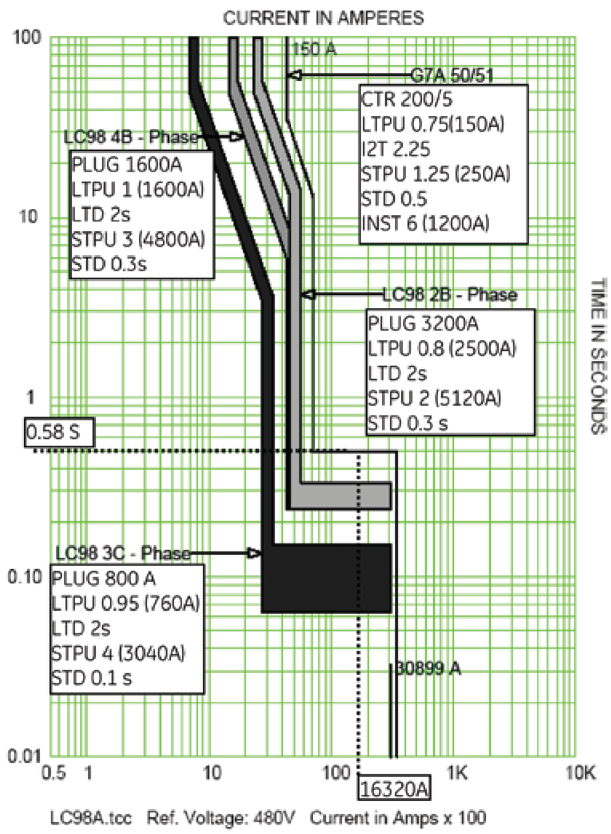

Figure 5.
New relay settings to reduce AF

Bus	Original AF cal/cm²	Improved AF cal/cm²
LC98 TX-A SEC	142	41
LC98 SWA MAIN CB LINE SIDE	136	39
LC98 SWG-A	24	17

Chart 5.
Normal operating mode AF levels

From chart 5 we can deduce that by modifying the relay and circuit breaker settings the AF incident energy can be less damage and the repair time will be subsequently reduced. The protective relays at the MV switchgear have available curves of the I²t characteristic that replaced the ANSI extremely inverse curve originally used. These curves have the advantage to better coordinate with downstream devices such as LV breakers with integral protective units.

Closed Tie Operation with Improved protection Settings.

The one line diagram on figure 7 illustrates the AF levels during closed tie conditions once the protective device settings were improved to reduce the AF in normal mode of operation. In figure 7 note that the arc flash risk went dangerously high when the tie breakers were closed to allow switching off a transformer for maintenance purposes. The AF level at the line side of the main breakers or busduct is close to 60 cal/cm².

Switching off transformers for maintenance.

A procedure to remove any of the transformers off service once the tie breaker has been closed is to open the feeder breaker at upstream substation first and later open the secondary side circuit breaker. Once the primary breaker is opened at the upstream substation, the busduct AF is reduced to 25 cal/cm².

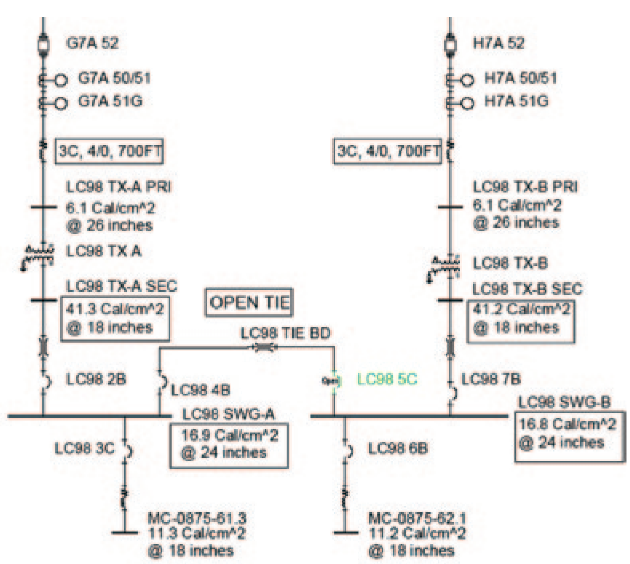

Figure 6.
One Line drawing with reduced AF. Tie breaker is open

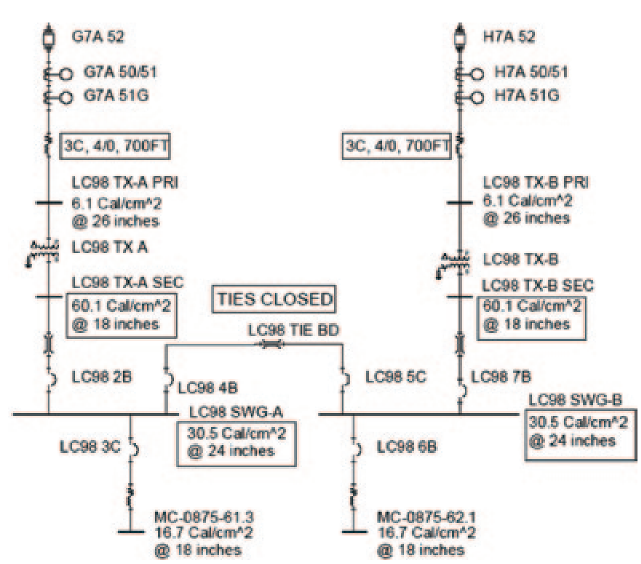

Figure 7.
Closed ties. AF with improved protective device settings

During maintenance activities the power distribution personnel will execute switching maneuvers to de-energize equipment. During these activities, the exposure to an arcing fault is increased. There are several methods to reduce the AF incident energy to lower levels; however, the coordination of the protective devices will be sacrificed.

8. Reducing the AF Incident Energy while in Switching Mode of Operation (Maintenance Mode)

The following conditions are set in order to understand the switching operation mode in regards to arc flash protection:

1. During switching operations and maintenance activities, the primary focus of attention is the safety of the personnel, subsequently, the sacrificing of protection coordination is necessary and the reliability of the power system is jeopardized.
2. An upstream device always clears an arcing fault.
3. The upstream device clearing the fault is normally located in a substation remote to the equipment being operated.
4. The utilization of other mechanical means to protect the personnel, such us PPE and remote controlled breaker racking devices, is not eliminated because of the application of these protective-relaying methodologies.

The following conditions are required to allow the system to implement a switching mode of operation:

1. The relay or breaker with integral protection unit must be able to change settings by the command of a control input or via communications.
2. An alarm to indicate that the relay settings have been changed and that the system is in switching mode of operation must be set.
3. Install Arc flash labels that indicates the incident energy on both modes of operation.

If the existing relays are electromechanical relays or if they are electronic relays but do not have the feature of changing settings groups then consider the addition of an instantaneous overcurrent relay to each feeder. This is also the case for integral-protection circuit breakers where the changing of protection groups is not supported.

The calculations to reduce the AF by modifying the relay settings must start at the lower end of the power system. In our study the lower end becomes the bus of the MCC's that operates at 480 VAC. The integral protection circuit breaker installed at the LV substation is the upstream device that will disconnect the circuit when an arcing fault occurs in the MCC and will be the breaker whose settings would be modified to introduce instantaneous settings during maintenance activities at the MCC level.

THE MAJORITY OF THE TYPICAL CAUSES INVOLVE THE INTERACTION OF PERSONNEL TO CREATE AN ARC FLASH FAULT

For the present paper only discusses the settings on protective relays installed at the MV switchgear that feed power to the MV/LV transformers. It is a common practice to provide a MV circuit breaker at the MV substation and then a long feeder cable feeding power to a MV/LV transformer. As seen in the case presented above, the arc flash incident energy is extremely high on the bus duct and at the line side terminals of the LV main circuit breaker. After studying the case to reduce the high incident energy to a more manageable value, the resultant numbers are not low enough to minimize the damage to the equipment and to reduce the risk imposed on personnel.

The typical causes of an arc flash fault are:

1. Accidental contact with energized parts
2. Tools dropped on energized conductors
3. Wiring errors
4. Improper work procedures
5. Contamination on insulators
6. Lack of maintenance on switchgear
7. Inadequate short circuit ratings

The majority of the typical causes involve the interaction of personnel to create an arc flash fault. The application of temporary protective device settings will reduce the risk of arc flash hazards by reducing the total incident energy should a hazardous situation develops as listed above.

The one-line on figure 8 and chart 6 shows the arc flash levels achieved when a different group of settings are utilized for maintenance activities performed downstream.

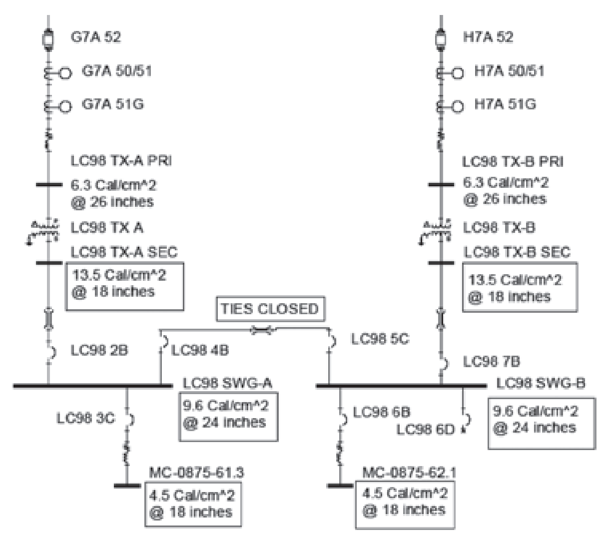

Figure 8.
Maintenance mode of operation; ties closed and minimum protective device settings

Bus Name	Protective Device Name	Bus Bolted Fault (KA)	Protective Device Bolted Fault (KA)	Protective Device Arcing Fault (KA)	Trip/ Delay Time (sec)	Incident Energy (cal/cm^2)
LC98 SWG-A (LC98 2B LINE SIDE)	LC98 2B	57.92	28.56	13.41	0.07	9.6
LC98 SWG-B (LC98 7B LINE SIDE)	LC98 7B	57.91	28.56	13.41	0.07	9.6
LC98 TX-A SEC	G7A 50/51	58.06	30.60	14.36	0.016	12
LC98 TX-B SEC	LC98 7B	58.06	27.46	12.89	0.07	13
MC-0875-61.3	LC98 3C	33.21	33.21	18.28	0.001	4.5
MC-0875-62.1	LC98 6B	33.21	33.21	18.28	0.001	4.5

Chart 6.
Maintenance mode of operation; ties closed and minimum protective device settings

While the arcing fault current remains the same, the tripping times are minimized and the resultant arc flash is reduced drastically. The coordination chart with the new settings group looks as shown on figure 9.

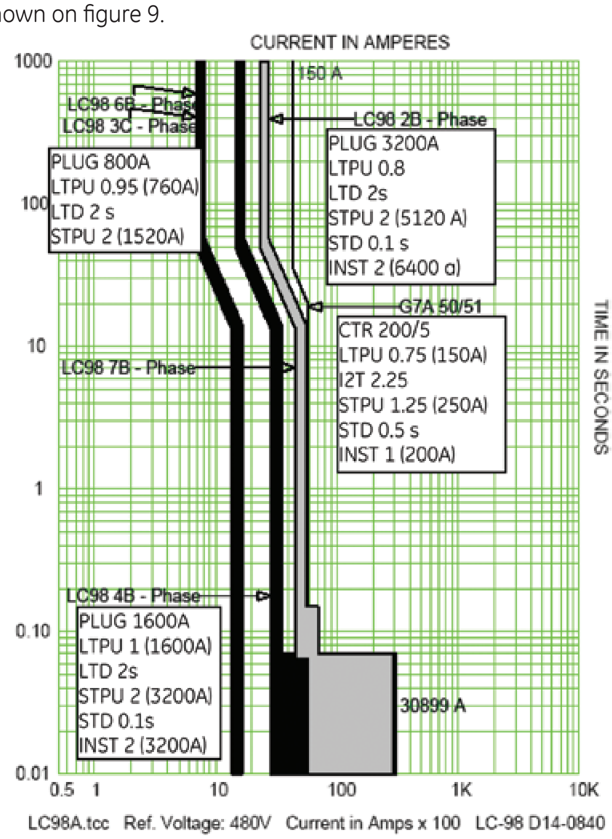

Figure 9.
Coordination chart as when in maintenance mode of operation

9. Methods to Change the Protective Relaying Settings for Switching and Maintenance Operations

1. Local maintenance mode switch. This control switch is wired into a digital input on the electronic protective relay to switch the normal operation group of settings to the maintenance mode. Special attention to the work order must be given since the protective relay and its corresponding control switch will be located remotely to the equipment to be serviced. The standardized work permit must include a field that specifies the location of the device and must include another field to insure that the switch was returned to its normal position once the labor has been completed. A pilot light to indicate this condition provides an easy way to acknowledge the condition of the protection scheme.

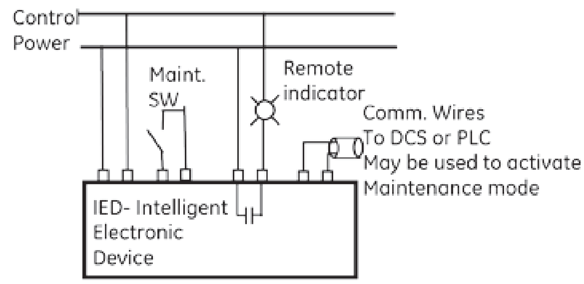

Figure 10.
Maintenance Switch to reduce AF levels during switching operations

2. Addition of a 3 phase Instantaneous Overcurrent Digital relay: If there is a set of three electromechanical relays and there is no intention to replace the relays for a microprocessor based relay; reduction of the AF incident energy could be accomplished by adding a compact instantaneous only digital device that could be added to the existing circuit and would provide the same functionality explained above.

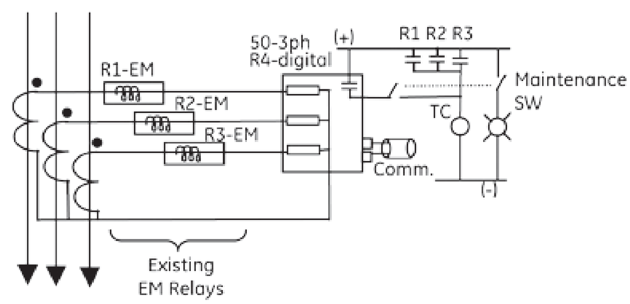

Figure 11.
The addition of an Instantaneous digital OC relay with existing electromechanical relay schemes

3. SCADA Systems. By utilizing the SCADA system in an industrial plant, the protective relay settings could be easily be changed to a different settings group for maintenance purposes during maintenance activities. It also allows the operation of circuit breakers from a remote location, which would reduce the exposure of the personnel during switching operations. Figure 12 is a typical screen where access to relay settings groups and circuit breaker control can be enabled after entering the rightful passwords and permissions.

Figure 12.
Typical SCADA control monitor

GOOSE MESSAGING CAN SIGNIFICANTLY REDUCE ARC INCIDENT ENERGY

10. Other methods for Continuous AF Protection

The following methods would provide continuous AF protection and would reduce the fault's clearing time significantly by automatically detecting the fault and issuing a trip signal once the fault is detected.

1. Zone interlocking via communications. Modern protective relays include protocols, such as, IEC61850 which allows GOOSE messaging amongst relays trough fiber optics. By using interrelay hi-speed I/O capability, blocking signals can be transferred upstream, allowing minimal coordination delays. In the system shown in figure 13, fast clearances can be provided for fault 1 and still maintain coordination for fault 2.

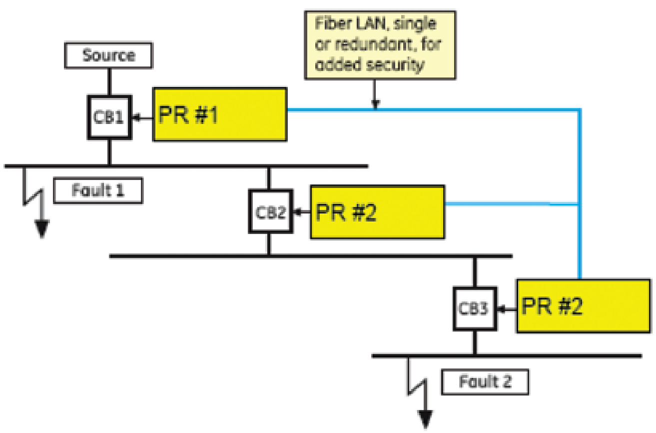

Figure 13.
Zone Interlocking

- Using GOOSE messaging can significantly reduce arc incident energy.
- If the fault is within the zone, no block signal is sent, the relay trips extremely fast.
- Redundant communication networks (LAN) can virtually eliminate the possibility of loosing communication amongst relays due to downed links.

2. Arc Detectors and High Speed Communication: Light sensitive technologies already exist and new technologies using other quantities are being developed to dependably and securely detect the arc flash and accelerate the tripping of the circuit breaker as soon as the arc starts. Arching is accompanied with several forms of energy such as light and heat. Fiber optic sensors can detect light and provide a signal to a protective relay input. The following two arcing fault cases illustrates the application:

• **Case #1.** In reference to figure 14 below, for an arcing fault at the cabling compartment at the load side of the feeder breaker, upon arc detection by the light sensor and supervised by an overcurrent condition, the relay IED #3 will issue a trip signal to the local breaker. If the arcing fault is located just before the location of the CT's or at the line side of the breaker, then IED#3 relay would send a message to IED#2 which would issue an instantaneous trip if an overcurrent condition is detected, reducing the incident energy to a safe amount.

• **Case #2.** For the system illustrated on Figure 14, where the transformer is located far from the main switchgear trough power cables, an arcing fault in the busduct or at the secondary compartment of the transformer would create a very low fault current at the substation feeder breaker and the relay at that location would take a long time to trip creating a very hazardous situation. When the light sensor at IED #2 detects the arc and since there is no overcurrent condition, then the arc detection flag will be send to the upstream device, via high-speed communication protocols. The trip is supervised by an overcurrent condition at the upstream device to assure selectivity.

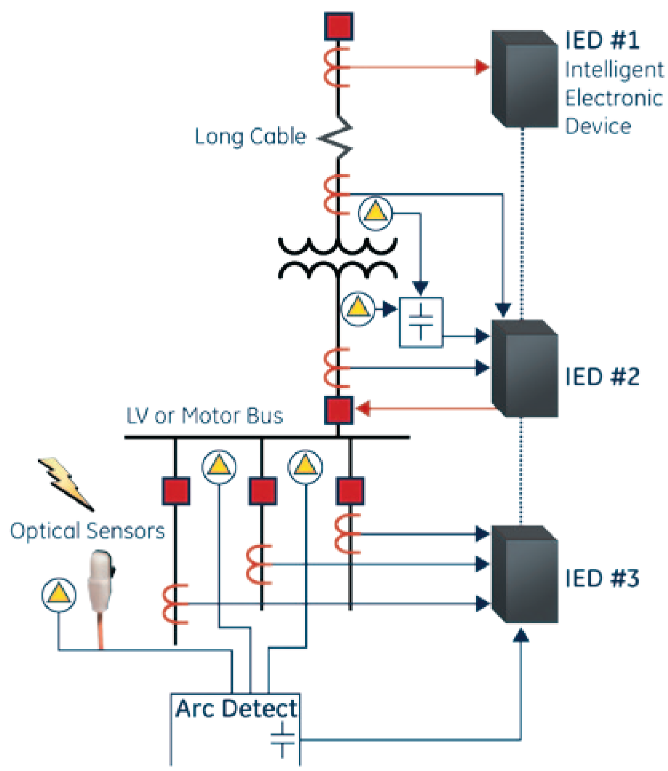

Figure 14.
Light detection and high speed communication technology

11. Conclusions

The modern technologies utilized by microprocessor based protective relays provide the means to accelerate the extinction of the arc produced by short circuits where the air is the conducting material. While appropriate personal protective equipment and increasing the distance of personnel from the electrical switchgear are the first line of defense to protect the people from hazardous risks; a well maintained electrical system, proper coordination studies and modern protective relays are the perfect companion for a safe working environment.

12. References

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An Industrial Power System Management for High Quality Uninterrupted Power Supply at Tata Steel

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1. Abstract

Industrial power system management has its own set of needs compared to a traditional energy management system. Foremost, in an industrial plant, all the transmissions assets including generation and loads are located within the geographical spread of the plant. The continuity of power supply becomes critical due to reasons of its complexities and potential threat of capital equipment damage once its water, steam and air circuit gets disturbed. In utilities, the revenue realization from the usages of energy remains as the highest priority, whereas, in a steel plant most important factor is to supply uninterrupted power even at the cost of underutilization of generation & transmission assets. The overall economics is driven by opportunity loss, risk assessment, safeguarding against potential equipment damage and faster restoration in case of outages or disturbances. This causes Load Dispatch Center (LDC) to gain significant importance with increased responsibilities.

This paper describes the implementation of Power Systems Management for LDC at Tata Steel. The architecture and features were developed by Tata Steel along with the vendors supplying the systems. This paper shows how such a system could benefit the operators in an industrial environment.

2. Introduction

Tata Steel is the world's 6th largest steel company, with an existing annual crude steel capacity of 28 million tons. Asia's first integrated steel plant and India's largest integrated private sector steel company is now the world's second most geographically diversified steel producer, with operations in 24 countries and commercial presence in more than 50 countries. Tata Steel is one of the few steel companies in the world that is Economic Value Added (EVA) positive. It was ranked the "World's Best Steel Maker" for the third time by World Steel Dynamics in its annual listing in February 2006. Tata Steel has been conferred the Prime Minister of India's Trophy for the "Best Integrated Steel Plant" five times.

Tata Steel's main steel division is located in Jamshedpur city in the Indian state of Jharkhand. Currently, the Jamshedpur works has an annual production capacity of 7 million tons and is planning to increase capacity to 10 million tons by 2010. The Load Dispatch Center (LDC) at Jamshedpur works is the power supply nerve centre for the whole of Jamshedpur, and is responsible for regulating the power generation and distribution at the Jamshedpur works, the town of Jamshedpur, and most of the neighboring industries. The electrical network managed by the LDC is comprised of the generation, transmission and distribution facilities as follows:

- Tata Steel's on-site generation, associated substations, transmission and distribution feeders
- Tata Power Company's generation and incoming feeders
- Tie-lines from the National Grid Damodar Valley Corporation (DVC) system to the Tata Steel network

The LDC is responsible for ensuring the smooth, integrated operation of the overall electrical network, and providing uninterrupted quality power to all customers at optimum cost. The operation of such an industrial power network spanning a very large steel plant is technically complex, and all the more critical from an operational standpoint.

3. Business Challenges

In order to facilitate the LDC requirements, a SCADA system was first envisaged in 1991. This system was procured from Siemens®. It went through a hardware upgrade in 2001 to replace the old and obsolete computers. The system at the time was limited to monitoring & control of a few critical load feeders for eight substations. LDC continued to function as a nodal point for controlling the maximum demand, load flow maintaining and restoration of power system after disturbances.

With significant growth in steel production and introduction of more power intensive process, soon it was evident that the system needed to be upgraded for effective power management. The key requirement was to be able to scan real-time data at a high-speed on a time synchronized platform for extensive data analysis and real time decision-making. Moreover, Electricity Act 2003 brought-in competition in the power sector. Trading allowed for the easier distribution of surpluses or deficits across the system and reflected economic pricing, while open-access empowered all constituents to choose the best options. To capitalize new business opportunities of power trading / open access system, enhancement of LDC system became critical and inevitable.

In view of the above, GE XA/21 SCADA system was envisaged under 1 MTPA expansion plan. This system with advance technology and extended geographical reach (all substations up to 6.6 Kv and selected 3 Kv substations) significantly improved the power system reliability through fast data acquisition, real time analysis, dynamic decision making and data warehousing. The system was further upgraded in 2007 as part of the 6.8 MTPA expansion plan. The expansion also included the advanced power systems applications like Transmission Security Management (TSM).

The following sections describe the XA/21 system architecture, applications and the advanced functionalities used in LDC.

4. System Architecture

The new SCADA system is a high-performance distributed control system that provides Tata Steel with the capability to monitor, control, and optimize the operation of geographically dispersed assets in real-time.

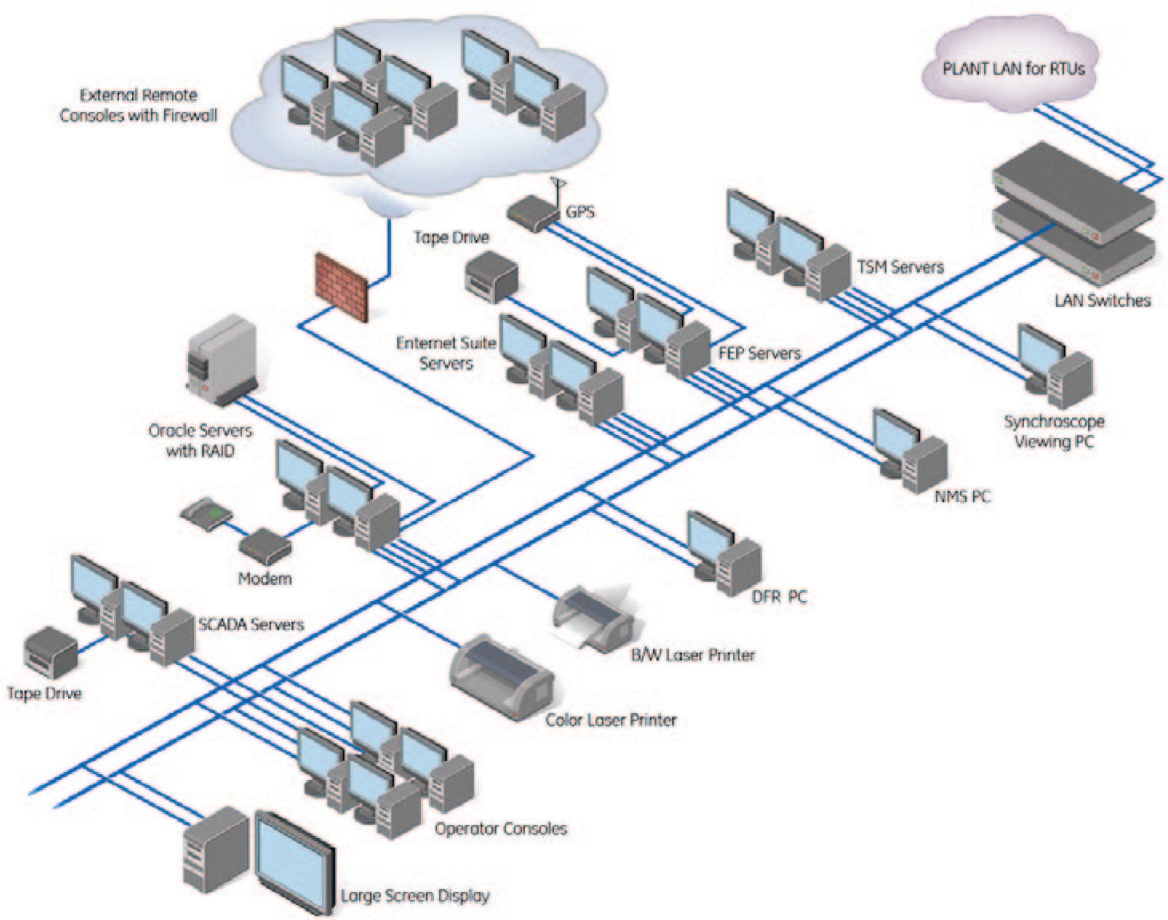


Figure 1.
Tata Steel LDC System Configuration

Flexible modular architecture permits the system to be reconfigured to meet future functional or performance requirements in a cost-effective manner. The SCADA system architecture is designed and customized to improve the overall power system reliability and enhance power management. While designing the system architecture, emphasis was given on high system availability through hardware redundancy and future expandability. The configuration is shown as per Figure 1.

The plant network is designed based on ring topology using 1GBPS fiber optic network to acquire real-time data such as electrical parameters, status of electrical devices and supervisory control function.

KEY REQUIREMENT WAS TO BE ABLE TO SCAN REAL-TIME DATA AT A HIGH-SPEED ON A TIME SYNCHRONIZED PLATFORM FOR EXTENSIVE DATA ANALYSIS AND REAL TIME DECISION-MAKING

4.1 Processor Servers

The Application Processors are based on the SUN Fire V240 machines. The SUN Fire V240 computers are specifically designed for high performance, expandability, ease of use, and supports extensive communications. The system architecture provides redundant servers for the SCADA Oracle, Front End Processor, TSM Application and the UI/Web functions. The primary and backup oracle servers share a RAID, which holds historical data information.

4.2 Local Area Networks and System Interconnection

The redundant Ethernet Local Area Network (LAN) serves as a data highway connecting the elements of the XA/21 System. The communication backbone within the plant is on Fiber Optic Network. There are two dedicated virtual LANs within the Tata Steel plant viz. the RTU LAN and the Control Center LAN. Both the LANs are redundant and hence failure of any one of the LANs does not have any impact on the data acquisition. Further route redundancy as well as core redundancy is also built into the design so as to ensure data availability in case of any contingency.

The Global Positioning System (GPS) receiver is used for keeping the system time synchronized with satellite time. This GPS receiver is connected to FEP server of XA/21 system, which periodically updates the times of other XA/21 nodes, RTU and third party system. This time synchronization from central GPS at LDC has enabled faster fault diagnosis using correlated events sequence recording, or real time voltage and current waveform for the affected system.

4.3 Real-Time Data Acquisition

The Real-Time data is collected at the 2-3 sec scan rates from the substations by the RTUs (Remote Terminal Unit) located at different substations. The communication between RTU to FEP (Front end processor) server is established through the redundant plant LAN and the IEC-870-5-104 protocol.

The integration of all local third parties SCADA system with central LDC with real time information has significantly enhanced the monitoring of critical power system parameter, facilitate fast decision making, fault analysis & restoration of power.

4.4 Device Control

One of the major limitations of the old system was that the device control was restricted from the central location. This resulted in delayed power restoration to critical plants processes, as most of the substations were unmanned. To overcome this limitation, a soft logic using the field input was developed for breaker control in the new system and tried successfully. On issuance of the control command by the operator from the HMI, the FEP server performs validation checks based on the built logic. If the request is valid, it issues the proper control signals to the RTU. To make sure the physical conditions are fine, breaker control process is supported by remote substation viewing from central LDC using high-end cameras.

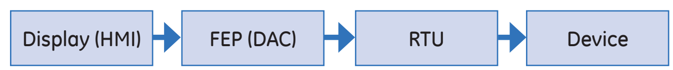


Figure 2.
Control Flow at the LDC

4.5 Network Management

Continuous monitoring of the health of SCADA network including the field devices, fiber optic cable and related Cisco switches is extremely critical to ensure 100 % availability of the system. In order to facilitate this goal, a Network Management System (NMS) was commissioned at LDC.

The main functionality of NMS is real-time monitoring (and reporting) and tracking of key information and data relating to device performance, traffic and environment, with metrics such as utilization percentage, frames transmitted and received errors and etc. on hardware, configuration and inventory changes. This has enabled Tata Steel to monitor the condition of the network from a remote location and faster fault localization in event of any failure.

5. Advance Analysis Features

In addition to the standard SCADA features like Data Acquisition, Data Processing, Calculated Data, Time Stamping, SOE Processing, Display Mimics, Alarm Display & Acknowledgement, List of Events Generation & Display Trends, following features of the new system has significantly improved the power management and hence the system reliability.

5.1 Power VU

For any electrical engineer, it is always a challenge to find out the root cause of any disturbance because of complex network structure, very fast occurrence of events and inability to simulate the fault condition. With the Power-VU playback functionality, it is now possible to review any past disturbance data and control the

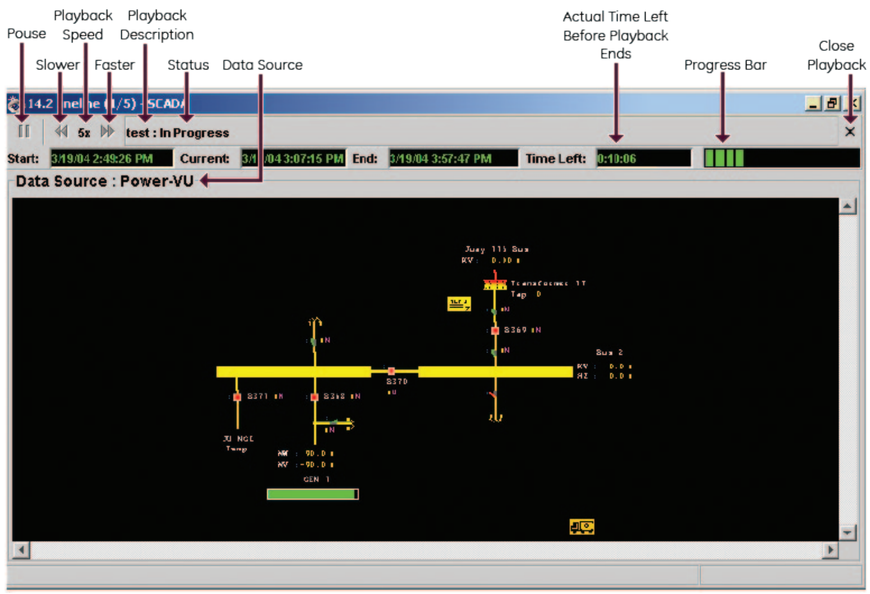


Figure 3.
Power playback in progress, and controls

review process by retrieving the historical data from the system. Sets of control displays are available for interaction with Power-VU (PV) as shown below.

The options available for individual playback consist of the following:

- Continuous Recording (CR) Playback: Provides the capability to review any online or archive-restored CR database. Changes are reviewed from telemetered and dispatcher sources that are within a time period determined by the online storage configuration for CR.
- Disturbance Data Collection (DDC) Playback: Provides the capability to review any online or archive-restored DDC Save Case data. The data contained within a DDC Save Case is collected from the CRDB for the time period of the defined disturbance.
- Contingency Analysis (CA) Playback: Provides the capability to review the results of the violation data from executions of CA within the Transmission Security Management (TSM) subsystem.

5.2 Video Trending

Trending conveys a great deal of information at a glance due to its visual impact and ease of interpretation. The video trend display provides us with the capability of graphically viewing general data tendencies and correlations as they vary over a period of time. In addition, trending affords the operator the opportunity to examine, using graph-like formats, the history of any analog point(s).

With growing complexity due to expansion in power system and limited resources at LDC, the visual aid become a very useful tool for shift manager to take fast decision and prompt action in event of any crisis.

There are two types of Video Trending: static and dynamic. Static and dynamic trends are visually identical and the data collection for the points involved is performed locally at the workstation. While static points are assigned through the Display Editor and cannot be changed by the dispatcher, dynamic point assignment is accomplished by the dispatcher through the UI.

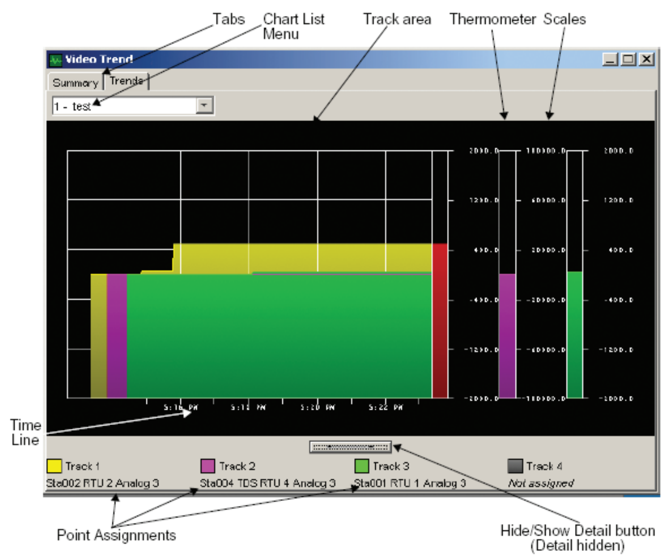
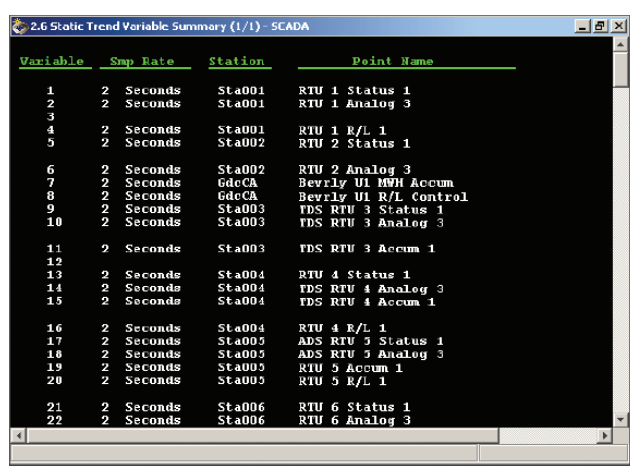


Figure 4.
Dynamic Video Trend Chart



Variable	Smp Rate	Station	Point Name
1	2 Seconds	Sta001	RTU 1 Status 1
2	2 Seconds	Sta001	RTU 1 Analog 3
3			
4	2 Seconds	Sta001	RTU 1 R/L 1
5	2 Seconds	Sta002	RTU 2 Status 1
6	2 Seconds	Sta002	RTU 2 Analog 3
7	2 Seconds	GdcCA	Bevrly U1 MWH Accum
8	2 Seconds	GdcCA	Bevrly U1 R/L Control
9	2 Seconds	Sta003	TDS RTU 3 Status 1
10	2 Seconds	Sta003	TDS RTU 3 Analog 3
11	2 Seconds	Sta003	TDS RTU 3 Accum 1
12			
13	2 Seconds	Sta004	RTU 4 Status 1
14	2 Seconds	Sta004	TDS RTU 4 Analog 3
15	2 Seconds	Sta004	TDS RTU 4 Accum 1
16	2 Seconds	Sta004	RTU 4 R/L 1
17	2 Seconds	Sta005	ADS RTU 5 Status 1
18	2 Seconds	Sta005	ADS RTU 5 Analog 3
19	2 Seconds	Sta005	RTU 5 Accum 1
20	2 Seconds	Sta005	RTU 5 R/L 1
21	2 Seconds	Sta006	RTU 6 Status 1
22	2 Seconds	Sta006	RTU 6 Analog 3

Figure 5.
Static Trend Variable Summary

5.3 SCADA Summary Windows

The SCADA Summaries window contains chronologically ordered, dynamically updated lists that display alarms, events, tags, and other off-normal conditions for points within the AOR assigned to shift Manager. A Freeze option freezes the dynamic data updates making point selection easier.

Seven types of summaries are provided, each on its own tab namely- Unacknowledged Alarms, Acknowledged Alarms, Events, Manually Entered, Off Normal, Tags & Memos.

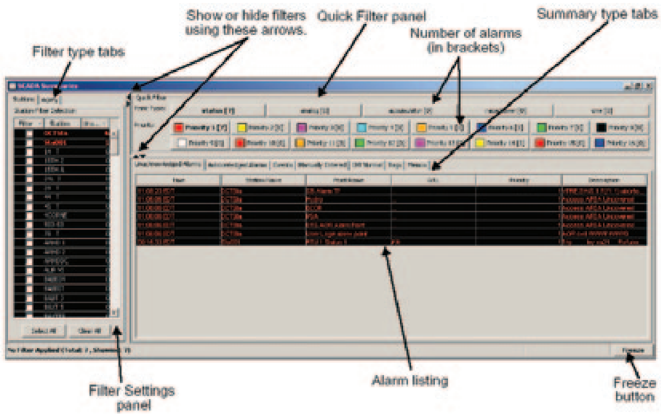


Figure 6.
Component of SCADA Summaries Window

5.4 Transmission Security Management

The primary purpose of the Transmission Security Management (TSM) Subsystem is to provide the user with effective tools to protect the power system's integrity and efficiently operate the system. Through these modules, the user is provided with additional knowledge of the real-time system while receiving the added benefit of being able to examine near future states of the system by exercising study mode functionality.

The TSM Subsystem provides network analysis, contingency analysis, and fault level analysis functions that play an increasingly important role in the operation of power systems. Through TSM, control center personnel are provided a means of identifying and analyzing potential operating problems as well as formulating various remedial / preventative strategies via transmission network application modules executing in an on-line system environment.

TSM software is composed of two types of modules:

- Real-Time Applications
- Study Mode Applications

Real-time applications assess the current state of the power system and consist of the following functions:

- Real-Time Network Analysis (RTNA)
- Real-Time Contingency Analysis (RTCA)
- Real Time Short Circuit Calculation (RSCC)

The RTNA function provides the operator with a detailed representation of the overall power system. It includes State Estimator function. RTCA executes subsequent to RTNA in order to assess the power system operating conditions resulting from the simulation of one or more pre-defined lists of contingency cases. RSCC function executes after RTNA to calculate three-phase, phase-ground, phase-phase and phase-phase-ground fault currents. The fault analysis in SCC is based on the positive (PSN), negative (NSN) and zero (ZSN) sequence network at the fault bus.

A study application allows the operator to interactively analyze, present and postulate system operating conditions. Study mode functionality can be utilized to study the effects of a switching operation prior to performing the actual operation. Each user's cases contain all input and output information needed to run any TSM application.

5.5 Application of TSM

Implementation in Tata Steel is to make use of such an advanced system, as TSM, for developing a Secure Operating Philosophy for its Power System Network. It is being used for performing network analysis, contingency analysis and network optimization functions using real time information that has helped to improve the system reliability. TSM runs on XA-21 system and take all necessary real time / snapshots information to carry out all its analysis. The data accuracy coming from field to the central SCADA system is extremely critical for success of TSM application and hence the reliability of the system. However, maintenance of entire network and ensure the accuracy of all information is difficult due various external factors e.g. failure of fiber optic cable, failure of IEDs or failure of any field devices.

The problem has been overcome by using the State Estimation (SE) feature of TSM system. In this SE continually estimate and identify the solvability of the power system. If part of the power system is not observable due to insufficient measurements, then SE identifies an observable portion of the system and solves it. The operator compares the out of the SE with SCADA output before carry out any real time analysis. This has enabled us not only to use real time data but ensure accuracy of the information. SE also helps operator to estimate the information essential for system study for any upcoming substation (not connected to SCADA system) using the existing information and certain technical parameter e.g. cable / overhead line length, expected load connected to that substation etc.

The maintenance of maximum system reliability has always been the primary concern of the power intensive industry. To attain this end, power systems are designed and operated so that for any predicted system condition, there will always be adequate generating and transmission capacities to meet load requirements in any system area. In order to achieve the same it is essential to proactively analyze (load flow & short circuit) all possible conditions for existing or any changed network configuration using real time data to check the reliability and carry out all possible contingency analysis to design the suitable preventive action before implementation. The TSM gives an edge over all other system analysis model, as it takes the real time data from the XA-21 SCADA system and uses it for load flow and contingency analysis. The real time information is copy as study case and all possible analysis are carried out. The result of the study case can be compare with real time case or any previously saved case.

In addition once the real time or the case study analysis is carried out for any new configuration , the TSM system generate reports in tabular form indicating the percentage violation for voltages for different buses, line loading, phase angle, reactive power etc for normal or base case configuration . If the violations are beyond acceptable limit, the operator analyze those violations and take corrective actions e.g. change the tap position in case of voltage, increase or decrease Active or Reactive generation etc and rerun the analysis using TSM system. Once all the violations for the proposed system configuration are within limit, operator approves the system for implementation. The short circuit study of the approved system is also done to see that all equipment is within the acceptable limit during fault condition.

Once the proposed configuration is approved for normal condition, contingency analysis is carried out to ensure the system behavior during any fault. TSM has a unique option called "Contingency Analysis". In this process user define all the possible fault / breakdown conditions in a tabular format as shown below and rerun the load flow and short circuit analysis using single contingency or multiple contingences. After each contingency analysis, all parameter violation are analyzed and suitable preventive action e.g. load shedding in event of less generation or line over loading, reactive compensation etc are designed. The entire process of analysis is carried out after incorporating all the proposed preventive action to take the contingency condition. After the analysis violation report are checks to ensure the effectiveness of the preventive measure. Once the report is satisfactory the new configuration is implemented along with all proposed preventive action. The multiple contingency analyses helped us to check the system before any change and hence improved the system reliability.

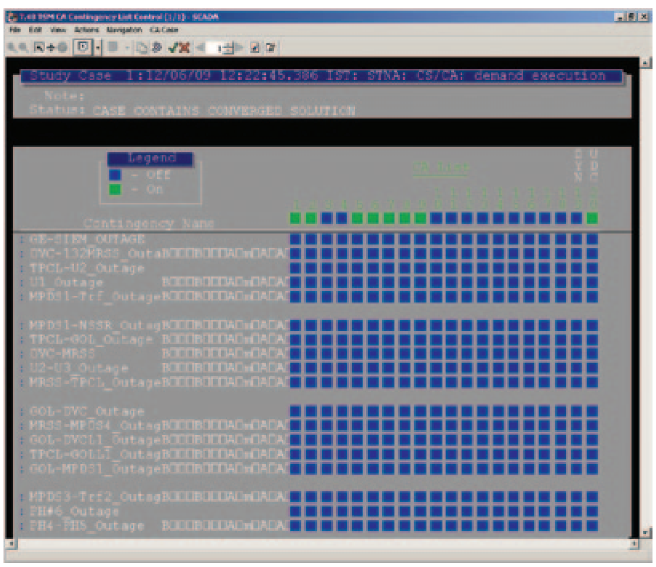


Figure 7.
Contingency List Control Window

6. Supporting Applications

Synchronization of Tata Steel power system with DVC grid is extremely critical activity. A wrong synchronization may lead to serious power system disturbance. Matching of voltage, frequency and phase angle within the technical limit is prerequisite for synchronizing any two-power systems. In past, this was done by controlling the generation from LDC by monitoring only the analog parameters with out seeing the actual movement of the synchroscope. Number of times in past, the synchronization process got delayed because of the same. The purpose of viewing synchroscope image from LDC during synchronization process was to improve the decision-making and helps in avoiding false synchronization. The collection of image was done using a high-end camera and transferred to LDC over fiber optic TCP/IP Ethernet LAN.

6.1 Dynamic Fast Load shedding (DFLS)

The maintenance of maximum system reliability has always been the primary concern of the power intensive industry. To attain this end, power systems are designed and operated so that for any predicted system condition, there will always be adequate generating and transmission capacities to meet load requirements in any system area. For the most part, this design and operating procedure has been successful in producing a high degree of service continuity, even under emergency conditions. However, regardless of how great the planned margins are in system design and operation, there have been, and probably always will be, some unpredictable combination of operating conditions, faults, forced outages, or other disturbances which cause system split-ups and/or a deficiency in generating capacity for existing area loading. When this occurs on a modern power system, it generally indicates that a highly improbable and potentially catastrophic event has occurred. Therefore, it is essential that the generation deficiency be quickly recognized and the necessary steps taken to prevent the disturbance from cascading into a major system outage. Dynamic Fast Load Shedding is a step towards this goal. The purpose of the Dynamic and Fast Load Shedding feature is to ensure the stability of the Tata Steel network by maintaining an acceptable balance between generation and demand in the event of pre-defined power system disturbances.

The response time from a contingency trigger to activation of a load shed is approximately 200ms. This is a reasonable achievement utilizing RTUs as opposed to protection relays.

The Dynamic and Fast Load Shedding performs the following functions:

a. Definition of contingency triggers by means of a user interface. This interface allows LDC to define a Boolean expression, which will be used to trigger load shedding.

b. Definitions of Priorities for individual loads are allowed.

c. Calculate the specific loads to be shed in the event of predefined triggers (contingencies). i.e. real-time analog values and fixed values using mathematical operators and propagates these calculated load-shedding definitions to the Master RTU for each defined trigger in every second.

d. Detection of the predefined contingency triggers, which should result in a load-shed sequence and processing them sequentially. Upon detection of a contingency trigger the loads to be shed will be recalculated at Master station and the new load shed definitions are downloaded to the Mater RTU within 1 sec.

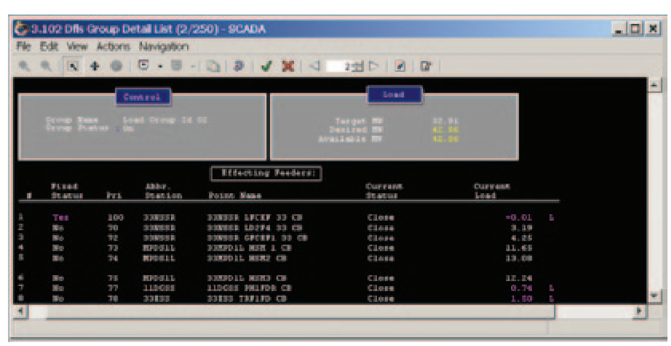


Figure 8.
Dynamic Fast Load Shedding Window

6.2 Economic Power Drawl

The raw material, labor and power constitute the major portion of the production cost in any industry. Any improvement in these areas has a significant impact on the bottom line of the company. Power cost primarily consists of the cost of generation and distribution. The cost of generation, distribution, T&D losses, taxes and subsidies and return required will determine the ultimate cost of power to the user.

The purpose of the Economic Power Drawl function is to ensure that the power sourcing at any given time is happening in most economical manner with in the given technical and physical limitation. The actual costs of generation as well as the optimum cost of generation subject to the various constraints are computed at periodic intervals. It also suggests the optimum loading for each generating plant/unit so as to drive the actual cost near to the optimum cost. To ensure minimum power cost for the steel works, LDC uses the output of the model to regulate the generation of all captive units, TPCL and drawl from DVC grid. This model can also be used as a reference during formulation of Annual Business Plan (ABP) and its validation.

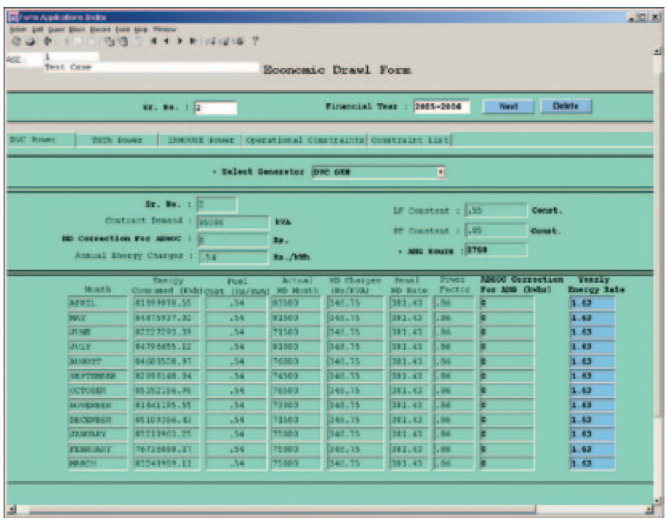


Figure 9.
Economic Power Drawl Window

6.3 Maximum Demand (MD) Control

The purpose of MD Control is to identify the causes of variation, which could result in exceeding the demand and create a solution to avoid excess drawl from DVC beyond the agreed value. This would lead to lower cost of power.

Presently the maximum demand is recorded based on integration of apparent (MVA) power over a period of 15 minutes, which is printed by the Trivector meter. Any maximum demand recorded by the Trivector meter in the month is taken as the Maximum demand for that month and is used for billing purpose. However, if the demand overshoots the upper limit, which is presently 120 MVA, then it is taken for the billing for the financial year for the purpose of computing the Demand Charges i.e., AMG & Penal Charges.

In case the demand is recorded below 75% of the Contract demand, the billing is done based on 75% of the contract demand only. Hence it is important to manage the demand from DVC within that band of 75% to 100% of the contract demand. In the event of demand exceeding 100% limit, the billing method of DVC puts severe financial burden on Tata Steel. Therefore it is necessary to check the excursion of the demand beyond 100% of the contract demand. If the forecasted demand from DVC exceeds 120 MVA, then the other generation sources has to contribute more or has to resort load shed of unimportant loads.

This system will not only continuously monitor and display the Maximum Demand, but also predict the projected Maximum Demand based on the past trend and indicate possible proactive action to contain the same. In event of Maximum Demand decided by the system exceeding the predefine value, auto load shedding will be done by the system to restrict the Maximum Demand within the predefine value.

6.4 Load Forecasting

The purpose of the Load Forecasting function is to predict the load in the future based on the historical information. Load Forecast uses data stored in the Historical Database. This data consists mostly of recorded historical demand data. Once the system database is populated with required data, the model can be effectively used for daily as well as future load prediction and hence further improve the power systems management.

7. Conclusion

This paper describes an implementation of Power Systems Management to improve the power system reliability and productivity in a steel plant. The system assists the Electrical T&D department at Tata Steel with the following:

- Monitoring the critical loads and ensure power system security through dynamic fast load shed with.

  - Pre-establish operating policies / contingencies.

  - Known constraint and existing demand supply condition.

- Ensure most economic drawl of power in order to meet the forecasted load while taking into account a variety of constraint.

- Efficient handling of emergency conditions and unscheduled events in order to:

  - Prevent local disturbances from becoming widespread system blackout.

  - Restore the system to normal operating conditions as quickly as possible.

- Remote substation monitoring and control to enhance the productivity and reliability.

9. References

[1] XA/21™ Release 9 documents.

[2] LDC upgrade Functional Design Specifications rotor bars in operating induction motors", IEEE transaction on Energy Conversion, volume 3, No.4, December 1988.

Riverside Public Utilities

Expansion Drives Need for Increased Communications Capacity

"The need for RPU to increase its communications capacity was driven mainly due to our back-up Energy Control Center requiring the same capabilities as the primary Energy Control Center; as well as our desire for video surveillance for substations and other mission critical facilities around the city," said Steve Badgett, Deputy General Manager, Riverside Public Utilities. "By simply upgrading the modules at the end of the existing fiber, we were able to easily increase the capacity of the existing fiber on the system and convert a single lane highway to 48-lane highway."

"When RPU purchased the JungleMUX OC-1 system, it was primarily a substation solution with the other communications aspects being secondary," says Rajiv Butala, Senior Electrical Engineer, Riverside Public Utilities. "Now, given our positive experience with JungleMUX and significant growth, we are utilizing more of the communications capabilities and decided to upgrade to a JungleMUX OC-48 system."

Riverside Public Utilities (RPU) is located in Riverside, California. The City of Riverside is the seat of Riverside County, California, and home to important facilities such as the court and board of supervisors, as well as numerous colleges and universities. RPU is the third largest municipal utility in the state of California by peak load. RPU has 107,000 residential and industrial customers.

Enabling Critical Communications with Dispatch Center

In 1996, RPU began using Lentronics OC-1 JungleMUX SONET Multiplexer to support the data exchange between 13 substations, two generating stations and eight communications sites to its dispatch center. These sites facilitate radio dispatch systems used by Utilities, Police and Fire departments to communicate between dispatch centers and field crews/safety officers. The JungleMUX takes all communications media (such as phone, protection and control data, Ethernet, SCADA, and video) and transmits it securely and dependably over fiber optic cables. The OC-1 system enabled RPU's dispatch center to gather data from its substations and provide it quickly and reliably to its field crews.

RPU had been successfully using the Lentronics system for five years when the City of Riverside's Fire and Police departments commissioned a study to see if they would also benefit from using a JungleMUX system to communicate between their dispatch centers and officers/staff in the field. The study showed that the Lentronics system would be more reliable than communications services from a telecom provider.

By 2001, the Fire and Police departments also moved to a OC-1 solution to facilitate communications between their dispatch centers and the field. Three Riverside municipal departments – Utility, Fire and Police – all using one fiber optic network enabled the city to coordinate its information technology group and maintain one fiber optic network system, reducing third party vendor communication, increasing reliability and bandwidth and enabling easier maintenance.

Company:

Riverside Public Utilities

www.RiversidePublicUtilities.com

Headquarters:

Riverside, California

Overview:

Riverside Public Utilities (RPU), established in 1895, is a municipally owned utility that serves the citizens and businesses in the City of Riverside, California. RPU provides high quality, reliable services to over 107,000 metered electric customers and 63,400 metered water customers (serving a population of nearly 300,000) in and around the City of Riverside. The electric utility is responsible for the generation, transmission, and distribution of electric power within the city. RPU's energy delivery distribution system consists of more than 538 miles of overhead lines and 587 miles of underground lines. 14 electrical substations and 124 distribution circuits serve the city.

GE Products and Services:

- Lentronics JungleMUX™ SONET Multiplexers
- VistaNet Network Management Software

Project Scope:

Upgrade an existing Lentronics JungleMUX SONET Multiplexer fiber optic system from OC-1 to OC-48 capacity to allow for additional bandwidth between substations, dispatch center and back-up dispatch center. Expand video surveillance from 3 to 14 substations around the city. Enable high definition video transport for up to 200 video sources.

Benefits:

- Secure, fast and reliable transport of critical information
- Increase bandwidth and capacity, allowing room for growth
- Ease of installation, operation and maintenance
- Protect capital investment with seamless capacity upgrade from OC-1 to OC-48
- Reduce connectivity, expansion and configuration costs with modular solution
- Comprehensive network management capabilities with VistaNET

Growth Leads to Need for Additional Bandwidth and Video Surveillance Expansion

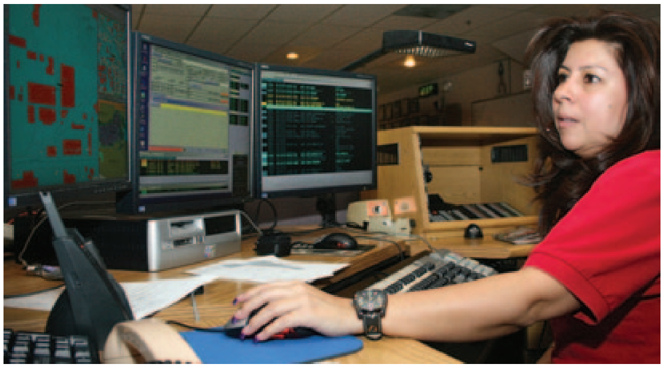
In 2005, due to system growth and the addition of a new back-up dispatch center, RPU was getting close to running out of bandwidth on its OC-1 system. If there was a major emergency and the dispatch center went down, the transfer of data from the dispatch center to the back-up dispatch center would have to be done manually which would be difficult and time consuming at a time when information is critical. RPU needed an automatic, reliable way to transfer data. In addition to the need for bandwidth and establishing communication with the new back-up center, RPU was planning to build out its video surveillance from three sites to all 14 of its substations.

Four Times the Bandwidth, Automatic Switching Capability and Easy Maintenance

RPU first looked at the OC-12 system that would give it the automatic switching capability and increased bandwidth that it needed. At the same, Lentronics was releasing the OC-48 system which had the same capabilities as the OC-12, but with four times the bandwidth. RPU determined that the OC-48, with its automatic switching capabilities and significantly more bandwidth, would allow it to expand its video surveillance and communications capability between generating sites.

With the OC-48, RPU also selected VistaNet Network Management software that allows the utility to operate and maintain the OC-48 system easily and efficiently. With VistaNet, access to the substation is password controlled by the utility and monitoring the JungleMUX equipment can be done remotely.

The upgrade to OC-48 was completed in Spring 2009 and took only three weeks to install in 13 locations. RPU is now deploying video at all its substations. Since the JungleMUX is backwards compatible, OC-48 installation was easy. RPU simply removed the existing OC-1 optical units and replaced with the new OC-48 units. The power consumption of comparable OC-48 solutions from other vendors would have been significantly greater. The OC-48 consumes only 5W per unit and minimizes the need for heat dissipation. Like the OC-1, OC-3 and OC-12 solutions, the OC-48 is passively cooled with no external fans required. In addition, the JungleMUX's IEEE 1613 substation hardening certification is a major requirement of critical utility communications products.



Industry Innovations

Featured Innovation

Complete Generator System Protection

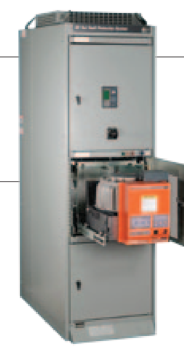
Multilin GPM Modules
GE Digital Energy – Multilin
www.GEDigitalEnergy.com/multilin

Complete Generator System Protection. In combination with the Multilin G60 Generator Protection System the new Multilin Ground Protection Modules for Stator (GPM-S) and Field (GPM-F) ground protection provides operational fault protection for your generator.

GPM-S 100% Stator Ground Fault Protection utilizes sub-harmonic injection to detect ground faults at any point across 100% of the stator winding, thereby protecting the complete stator winding and allowing early detection of stator ground fault conditions.

GPM-F Field Ground Protection Module detects ground faults in the field winding of the generator. Providing application flexibility, the field ground protection module can be configured for either single point or double point injection based on your application requirements.

Arc Fault Protection System



Arc Vault™
GE Industrial
www.GEIndustrial.com

Arc Vault™ sets the new standard for arc fault protection. With an innovative approach GE's Arc Vault™ extinguishes the arc flash. Arc Vault™ can stop an arcing fault in less than eight milliseconds, a fraction of the time that traditional systems need to stop a flash. The Arc Vault™ solution saves you money by reducing downtime, decreasing switchgear damage, and the ability to be added as a retrofit, the Arc Vault™ enables you to maximize your return on your existing equipment.

iFlex Flexibility With Remote Reading Capability

Fluke 381 – Remote Display
Fluke
http://www.fluke.com

The Fluke 381 Clamp Meter combines iFlex flexibility with remote reading capability. The iFlex flexible current probe measures large conductors and provides access in tight spaces. The detachable digital display allows you to attach the meter in one place and take the reading in another, up to 30ft away. It's like being in two places at once. CAT IV 600 V CAT III 1000V rated, the Fluke 381 combines innovation with safety.

Superior Selectivity & Arc Flash Energy Protection

EntelliGuard® TU
GE Industrial
www.GEIndustrial.com

The EntelliGuard® TU trip unit provides superior selectivity and arc flash energy protection. IT replaces installed trip units on Power Break® I and II, AK/AKR, and WavePro® and is standard on the new EntelliGuard G circuit breaker.

GE's EntelliGuard TU is the trip unit with the built-in flexibility required to match your system's needs, whether for optimum safety, optimum system reliability, or both at the same time. Whether you're using all GE circuit breakers or a mixed system of breakers and fusible devices, the EntelliGuard TU will accommodate your needs with minimal compromise and maximum functionality.

Industry Innovations

Thermal Imaging for Predictive Maintenance Inspections

T640 – Thermal Camera
Flir
www.flir.com

For the most demanding thermal imaging camera users, FLIR Systems introduces the FLIR T640 / FLIR T620 thermal imaging cameras for predictive maintenance inspections. Both the FLIR T640 and FLIR T620 are equipped with state-of-the-art uncooled microbolometer detector that produces crisp thermal images of 640 x 480 pixels on which the smallest of details can be seen. This results in reliable inspections with greater accuracy. The new FLIR T640 / T620 also incorporates a 5 megapixel visual camera. It generates crisp visual images that can be used as a reference against the thermal image in all conditions. A LED lamp allow for taking visual images also in extremely dark environments.

Electric Vehicle Charging for Cities and Businesses

WattStation™
GE Industrial
www.geindustrial.com/products/static/ecomagination-electric-vehicles

GE's WattStation™ - Electric Vehicle Charging for Cities and Businesses

GE's WattStation enables fast Level 2 charging at home and on the road. The modular design by renowned industrial designer Yves Behar is upgradable as more communication options become available. This allows customers to stay current with the latest technology in a rapidly changing space, while providing the ability for commercial property owners to qualify for LEED points.

Full Resistance Measurement Capability

MTO3xx Series Transformer Ohmmeters
Megger
www.megger.com

The MTO 3xx Series Ohmmeter Automated Six-Winding Transformer Ohmmeter delivers full eight-terminal/six-winding resistance measurement capability. It is designed to save time for the user by testing all normal 6 windings without having to disconnect and reconnect leads during testing. The MTO 3xx Series also shares the Megger TTR 3xx series lead set. Users who test both turns ratio and winding resistance can save time and money since only one lead set is needed to connect to the transformer.

Versatile Three-phase Testing Solution

CMC 353 - New Compact Protection Test Set
OMICRON
www.omicronusa.com

OMICRON's latest protection test set, the CMC 353, provides the perfect combination of portability and power with its compact design, light weight (28.4 lbs / 12.9 kg) and powerful sources (3 x 32 A / 430 VA; 3 x 300V). The CMC 353 meets a wide variety of challenges in the field — from testing electromechanical relays to the latest IEC 61850 IEDs. It is the ideal test set for three phase commissioning tasks and checking SCADA systems.

Upcoming Events

CIGŔE | Sep 12 – 15 | Lausanne, Switzerland

GE Digital Energy will be presenting the following papers at the 2011 conference:

- Modelling of ENTSO-E/Turkey Interconnection for Testing of Special Protection System (SPS)
- Implementation of a Special Protection System (SPS) in the Interphase between the Turkish and ENTSO-E Power Systems to Counteract Propagation of Major Disturbances

École Polytechnique Fédéral de Lausanne (ÉPFL)
www.cigre-scb5-lausanne2011.org

Visit GE Digital Energy in the Exhibition Area

IEEE Africon | Sep 13-15 | Victoria Falls, Livingston, Zambia

IEEE Zambia Section

GE Digital Energy will be presenting the following papers at the 2011 conference:

- Implementation of a Special Protection System (SPS) in the Interphase between the Turkish and
- ENTSO-E Power Systems to Counteract Propagation of Major Disturbances
- Advanced Load Shedding, Load Restoration and Substation Control Schemes Based on IEC61850 in Distribution Substations

Falls Resort & Convention Centre
www.africon2011.co.za

Visit GE Digital Energy in the Exhibition Area

IEEE/IAS | Sep 19 – 21 | Toronto, Ontario, Canada

The IEEE/IAS PCIC provides an international forum for the exchange of electrical applications technology related to the petroleum and chemical industry. The PCIC annual conference is rotated across North American locations of industry strength to attract national and international participation.

Nightly Hospitality Suite – September 18-20
Sheraton Center Toronto Hotel

GE Digital Energy will be presenting the following papers at the IEEE/IAS PCIC 2011 conference:

- Evaluation of New Technologies in the Detection and Mitigation of Arc Flash
- The Power of IEC61850 for Bus Transfer and Load Shedding Schemes

Sheraton Center Toronto Hotel
http://www.ieee-pcic.org/Conferences/2011_Toronto

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BH K CIGŔE | Sep 25-29 | Sarajevo, Bosnia and Herzegovina

GE Digital Energy will be presenting the following papers at the 2011 conference:

- Differential Protection for Power Transformers with Son-Standard Phase Shifts
- Distributed Automatic Transfer Bus and Restoration Using IEC61850

Radon Plaza Hotel
www.bhkcigre.ba/english/ebhkcigre.htm

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Upcoming Events

MAKO CIGŔE	Oct 2-4	Ohrid, Republic of Macedonia

GE Digital Energy will be presenting the following papers at the 2011 conference:

- Impact of CT Errors on Protective Relays – Case Studies and Analysis
- Distributed Automatic Transfer Bus and Restoration Using IEC61850

Hotel Metropol Lake Resort
http://2011.mako-cigre.org.mk

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WPRC	Oct 18-20	Spokane, Washington, United States

Pre-Conference Seminar
Fundamentals and selection of Current and Voltage Transformers - October 17
Spokane Convention Center – Rooms 206AB

Nightly Hospitality Suite – October 17-19
Red Lion Hotel Inn at the Park – Skyline Ballroom II

Spokane Convention Center
www.capps.wsu.edu/conferences/wprc

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MIPSYCON	Nov 1-3	Minneapolis, Minnesota, United States

GE Digital Energy will be presenting the following papers at this event:

- Differential Protection for Power Transformers with standard and Non-Standard Phase Shifts

Pre-Conference Seminar

GE Smart Substations – Technology Update & Fundamental Concepts - October 31, Grandview Ballroom

Hospitality Suite – October 31, Grandview Ballroom, Embassy Suites Hotel

Vendor Exhibitor Reception – November 1, Earle Brown Heritage Center

Embassy Suites Hotel Minneapolis – Brooklyn Center
www.cce.umn.edu/mnpowersystems

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Upcoming Events

CIGŔE Croatia	Nov 6-10	Cavtat, Croatia

GE Digital Energy will be presenting the following papers at the IEEE/IAS PCIC 2011 conference:

- Implementation of a Special Protection System (SPS) in the Interphase between the Turkish and ENTSO-E Power Systems to Counteract Propagation of Major Disturbances
- Advanced Load Shedding, Load Restoration and Substation Control Schemes Based on IEC61850 in Distribution Substations

Cavtat, Croatia
www.hro-cigre.hr

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For the latest event information visit our website: www.GEDigitalEnergy.com/multilin/EventCalendar.htm

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Advanced Training

GE Multilin 2011 Course Calendar

Comprehensive Training Solutions for
Protection, Control and Automation

SCHEDULED COURSES IN NORTH AMERICA

	Courses for 2011	Tuition*	CEU Credits	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Protection & Control	UR Advanced Applications	$3,000	3.5						24-28		
	UR Platform	$1,800	2.1		20-22		9-11		19-21		
	Distribution Management Relays	$1,800	2.1	16-18			16-18				
	Fundamentals of Modern Protective Relaying	$2,400	2.8			11-14		12-15		14-17	
	Motor Management Relays	$1,800	2.1		8-10			27-29			6-8
	Enervista™ Software Suite	$600	0.7		6-7			30			9
	IEC61850	$2,400	2.1	3-5					3-5		
Substation Automation	D20/D200 with ConfigPro	$2,550					15-19		31	1-4	
	D25 with ConfigPro	$2,550				11-15					
	D400 Essentials	$1,750					23-25			8-10	
	iBox with ConfigPro	$2,150				18-21					
	DNP3 I/O Modules	$1,000				22					

All North American courses are located in Markham, Ontario, Canada unless otherwise stated
*Tuition quoted in US dollars

SCHEDULED COURSES IN EUROPE

	Courses for 2011	Tuition*	CEU Credits	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Protection & Control	UR Advanced Applications	$3,000	3.5	16-20 (English)		18-22 (Spanish)				14-18 (English)	
	UR Platform	$1,800	2.1	11-13 (English)		13-15 (Spanish)				9-11 (English)	
	Fundamentals of Modern Protective Relaying	$2,400	2.8		6-9 (English)				17-20 (Spanish)		
	Distribution Management Relays	$1,800	2.1	2-4 (Spanish)				5-7 (Spanish)			
	Motor Management Relays	$1,800	2.1					12-14 (English)		21-23 (Spanish)	
	F650 Platform	$1,800	2.1		13-15 (French)		1-3 (Spanish)				12-14 (English)
	IEC61850	$2,400	2.1				4-5 (Spanish)				15-16 (English)
Substation Automation	D20/D200 with ConfigPro	$2,550			13-17 (English)		1-5 (English)		17-21 (English)		
	D25 with ConfigPro & DNP I/O Modules	$2,550			6-10 (English)		8-12 (English)		3-7 (English)		
	D400 Essentials	$1,750		2-6 (English)		11-15 (English)				7-11 (English)	
	D400 and D25 with IEC 61850	$2,550		9-13 (English)		18-22 (English)				14-18 (English)	
	Ibox with ConfigPro & DNP3 I/O Modules	$2,550						12-16 (English)			
	PLA	$2,550						19-23 (English)			12-16 (English)

All European courses are located in Bilbao, Spain unless otherwise stated
*Tuition quoted in US dollars

Course dates are subject to change. Please visit our website at **www.GEDigitalEnergy.com/Multilin/training** for the most up-to-date schedule.

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