ELECTRICAL EQUIPMENT MODERNIZATION PROJECT – A CASE STUDY

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Abstract – The objectives of this project were to modernize electrical equipment within pumping stations to reduce arc flash levels, add protective devices for improved protection, and provide data for preventative maintenance and easier troubleshooting. These pumping stations are approximately every 30 miles between Houston, Texas and Linden, New Jersey. The installation of low impedance bus differential protection reduced the tripping time for bus faults and reduced arc flash incident energy levels. Motor protection relays were installed to protect the motor and collect actual data to assist in troubleshooting, measurement of pump efficiency, pre-motor failure notification and aid in operation controls. A remote measurement and control architecture enabled transformer protection using fiber optic communications which reduced current transformer saturation. Digital monitoring equipment with command capability was installed to access all protective relays operational data and trip resets could be performed from outside the arc flash boundary. This paper will discuss the lessons learned during design, installation and operation. The lessons learned aided the pipeline throughout the design, installation and operation phases of the project.

Index Terms – Arc Flash, Intelligent Electronic Device (IED), Generic Object Oriented Substation Event (GOOSE), Low Impedance Bus Protection, Motor Protection, Transformer Protection, Programmable Logic Controller (PLC), Human Machine Interface (HMI), SCADA (Supervisory Control and Data Acquisition), Local Area Network (LAN), Rapid Spanning Tree Protocol (RSTP), OPC (OLE for Process Control), Fiber Optic Ring Network.

I. INTRODUCTION

Modern protective relays offer many advantages over their electromechanical predecessors. Since these modern relays are microprocessor based they can easily perform additional functions other than just traditional protection such as device-to-device logic and motor broken rotor bar monitoring. Additionally, they can incorporate several protective features into a single package. These features enhance protection of the primary equipment and provide improved personnel protection in the form of enhanced arc flash protection, improved diagnostic information about the equipment being protected, and improved operational information based on the measured quantities available to the protective relay. Since these functions go beyond the traditional role of a protective relay, the term Intelligent Electronic Device (IED) has been used to describe these devices.

Enhanced arc flash protection is achieved with bus differential relaying. With differential relaying, the current into the zone of protection and the current out of the zone of protection are compared. Unless there is a fault, these values should sum to zero. During fault conditions, there is differential current and the element can trip. Differential protection operates fast because it has a well-defined zone of protection and does not over-reach its zone of protection. This means for differential protection of a bus or a transformer, the protection can be relied on to trip for faults within the bus or transformer and can be relied on to restrain for faults outside of this zone of protection. Unlike time overcurrent protection, differential protection does not have any intentional time delay which allows these elements to operate fast and reduce the arc flash incident energy. Additionally, protective features, like breaker failure protection was incorporated into the IED protection scheme to provide protection for failed circuit breakers.

Modern IEDs also provided improved diagnostic information about the systems they protect. This information includes stator temperature, bearing temperature and broken rotor bar detection alarms. This information increased availability of the primary equipment because issues can be identified before they cause equipment failure and allow operation personnel to schedule maintenance to correct these issues, when the equipment is least needed.

The diagnostic information combined with metering information gives company personnel better situational awareness of their system. Operations department can obtain alarm information and access to metering and protective information from the system. Examples of this type of

information include motor total lockout time, bus voltage level, and motor load data.

In order to get this information from the IED to the operator in a manner that can quickly and easily be communicated, the IED must have excellent communications capabilities. This required the IEDs in this project to have Ethernet network communication capabilities. Additionally, the protective and operational schemes were enhanced by communications messages between the IEDs. The IEC61850 standard has a communications protocol for this type of peer-to-peer messaging called Generic Object Oriented Substation Event or GOOSE message. These GOOSE messages are broadcasted messages that are sent on changed of state, unlike Modbus protocol, which is a master-slave protocol with the Modbus master first making a request before information is transmitted. These GOOSE messages use the same Ethernet architecture as the operations data interface. Since the GOOSE messages are used for protection in this project, they required redundancy such that the IEDs have redundant Ethernet ports and the physical architecture be arranged in a ring architecture.

Monitoring and control of IEDs by PLCs (Programmable Logic Controller) and maintenance HMI (Human Machine Interface) is vital for the operation and diagnostics of a pipeline's pumping stations. A fault tolerant, secure and reliable Ethernet network configuration was a requirement for the modernization project. The PLC will monitor each IED and perform the necessary control functionality to properly start and stop each motor at station.

II. PROJECT GOALS AND OBJECTIVES

A. Protection and Control

The goals and objectives of the project pertaining to the protection and control system were as follows:
1) Remove electromechanical relays and install advanced protective and control devices (IEDs) with peer-to-peer communications to reduce maintenance intervals, wiring, and providing metering and diagnostic data.
2) Install low impedance bus differential protection to reduce tripping time for bus faults and reduce arc flash incident energy levels.
3) Install advanced motor protective devices to protect motor and collect data to assist in troubleshooting and pre-motor failure notification.
4) Install advanced transformer protection using a fiber optic remote measurement and control architecture.

B. Communications, Network and Monitoring

The goals and objectives of the project on the communications and data side were as follows:
1) Provide diagnostic information to the pipeline's technicians and engineers that is available locally and remotely.
2) Provide a fault tolerant communications architecture that allowed for a single communications link to fail and still provides for IEC61850 GOOSE messaging between devices and pipeline's SCADA system.
3) Integrate the new intelligent electrical devices into the pipeline's existing SCADA (Supervisory Control and

Data Acquisition) communications and control scheme with minimal operator impact.
4) Prevent remote intelligent electronic device configuration changes without express consent from local station personnel.

III. SYSTEM DESIGN

A. Protection and Control

Advanced microprocessor based protection and control IEDs were installed on this project. Figure 1 shows a typical protection one-line for a single line-up in a pumping station. See Appendix A for enlarged Figure 1. Each station had a different number of motor relays and one or two transformers. Elimination of unnecessary device to device wiring was crucial for the project to simplify installation and enable advanced functionality [1]. Using IEC61850 GOOSE messaging in the project reduced device to device wiring [2]. Motor protective relay was wired to trip, control and monitor each motor. Transformer protective relay was wired to trip, control and monitor the utility circuit breaker. Bus protective relay was wired to trip, control and monitor main bus breaker. Breaker open/close status is monitored by each respective protective relay. If bus or transformer protective relay needs to trip a motor, IEC61850 GOOSE messaging was used between the bus relay, transformer relay and motor relays.
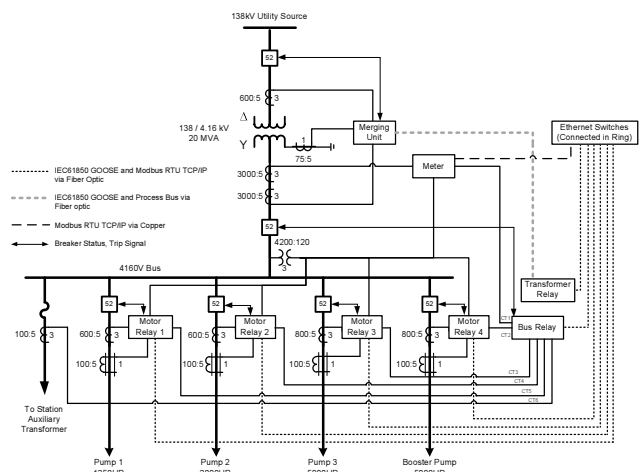

Fig. 1 – Station Protection & Control One-Line

Advanced motor protective relays provide protective trip condition of motor for short circuit, motor differential, ground overcurrent, motor thermal overload, current unbalance, winding over-temperature, current unbalance, mechanical jam, overvoltage, undervoltage, acceleration time, voltage unbalance, breaker failure, switchgear door open, motor over-vibration, pump over-vibration, stator over-temperature, motor inner bearing over-temperature, motor outer bearing over-temperature, pump inner bearing over-temperature, pump outer bearing over-temperature, pump, case over-temperature and 480V motor control center trip condition [3]. The 480V motor

control center trip condition is received by a GOOSE message into the motor relay from the bus relay. The bus relay has a contact input go high when a 480V motor control trip occurs. Some motor trips are latched and motor cannot be started until motor cools, starts-per-hours or time-between-starts automatically reset per configured parameters or until fault condition is acknowledged by field personal.

Breaker failure protection was implemented in this project. Breaker failure is the presence of current after a time delay with initiation by a trip condition. Failure of a motor breaker issues a IEC61850 GOOSE message, which is received by bus protection relay to operate the main bus breaker.

Motor alarms provided by the motor protective relay include stator over-temperature, pump case over-temperature, motor over-vibration, pump over-vibration undervoltage, current unbalance, ground overcurrent, broken rotor bar, voltage unbalance, motor thermal overload, motor inner bearing over-temperature, motor outer bearing over-temperature, pump inner bearing over-temperature and pump outer bearing over-temperature. The project design included replacement of existing class C20 current transformers with class C100 current transformers on all three phase motor currents to minimize CT saturation during bus faults. Advanced motor monitoring/alarms used in the project are broken rotor bar, breaker trip coil circuit open, thermal model inhibit, starts per hour inhibit, time between starts inhibit, motor running, motor stopped, motor starting, motor running time (minutes and hours), breaker operation counter, breaker position (open/closed), open RTD (winding or bearing) and shorted RTD (winding or bearing).

Total motor lockout time, which is maximum of all lockout times (thermal lockout time, start-per-hour lockout time, time-between-starts lockout time) aids the operator to select a running motor to manually stop with the lowest total motor lockout time. The motor with the lowest total motor lockout time is the motor that would be the first available to be re-started after a manual stop has been issued.

Low impedance bus protection allowed the pipeline to use existing motor phase current transformers with different ratios [4]. When a bus fault occurs, the main bus breaker is tripped by the bus relay and a IEC61850 GOOSE message is sent out. This GOOSE message is used by each motor relay to trip respective motor breaker. The installation of low impedance bus protection improved the trip time for bus faults to 1 cycle plus breaker operating time and lowered the arc flash incident energy dramatically. Actual measured operating time for a bus fault was 54 ms. Prior to low impedance bus protection installation, the operating time for a bus fault was approximately 600 ms including breaker operating time. Since the bus relay measures the phase currents of each motor relay and the main bus breaker, the bus relay implements back-up short circuit protection for each motor

relay and overcurrent protection on the main bus breaker. The bus relay monitors the main bus breaker position status (open / closed) and trip coil circuitry. All trips by bus relay are latched and main bus breaker and motor breakers cannot be closed until fault condition is acknowledged by field personal. Programmable logic and GOOSE messaging was used to reset all associated devices tripped for a bus fault.

A remote measurement and control architecture was used for transformer protection with fiber optic communications [5,6] (see Figure 1). See Appendix A for enlarged Figure 1. The system used IEC61850 GOOSE messaging and IEC61850 process bus with hardware consisting of a transformer protection relay and a remote field unit (merging unit). The remote field unit (merging unit) was connected to the transformer protection relay with fiber optic cabling due to the long distance between the power transformer and location of the transformer protection relay. The remote field unit has high-side three-phase current inputs, low-side three-phase current inputs, ground current input, utility breaker position status (open / closed) input, external sudden pressure trip input, oil temperature dcmA input and latching utility breaker trip contact. Using fiber optic cabling allowed quick installation and minimized current transformer saturation since there are no long CT cable runs which can cause CT saturation. The advanced transformer protective relay provided protective trip of transformer for phase differential, ground overcurrent, high-side winding overcurrent protection and external sudden pressure trip. When a transformer fault occurs, the utility main breaker is tripped by the transformer protection system and a IEC61850 GOOSE message is sent out. This GOOSE message is used by bus relay to trip the main bus relay and the bus relay sends a GOOSE message that is received by each motor relay to trip respective motor breaker. All trips by transformer relay are latched and utility breaker and main bus breaker cannot be closed or any motor started until fault condition is acknowledged by field personal. Programmable logic and GOOSE messaging was used to reset all associated devices tripped for a transformer fault.

Transformer monitoring/alarms include hot oil over temperature via transducer input from remote field unit, utility breaker position (open/closed) and breaker trip coil circuit open.

A transfer switch was wired into both bus relays to designate that both lines have been tied together and the transfer switch is closed. During this arrangement, a transformer or bus fault on an adjacent bus or adjacent transformer causes a complete system trip condition (using IEC61850 GOOSE messaging) of all motor breakers, main bus breakers and utility main breakers.

The off-line status of each remote IED using GOOSE messaging is annunciated using target LEDs on the protective relay. This aided in GOOSE messaging check-out during installation, troubleshooting and operation.

Hardware/device failure contacts are monitored on each of the installed IEDs and remote field unit. Communications failure or hardware failure of a remote field unit cause a transformer trip. A hardware failure of a transformer relay is a hardwire input to the bus relay and cause a trip of main bus breaker and all motors. A hardware failure of a particular motor relay stops the motor and blocks start.

Mechanical lockout relays were eliminated in the design reducing maintenance and as mentioned previously the lockout functionality was implemented in the associated motor, bus and transformer protection relays.

To assure that the necessary event data and oscillography waveform data has been recorded for each trip condition on each line, oscillography cross triggering was implemented between all motor, bus and transformer relays using IEC61850 GOOSE messaging, so all devices have records for any single trip condition at the station.

B. Communications, Network and Monitoring

1) *Communications*: A generic solution with the most equipment possible was developed because the design would be applied to multiple locations and station configurations. The configuration included two distinct lines of equipment at one station, while the lines of equipment would largely be the same, communications between the lines of equipment would also be required. The control system utilizes a common Modbus RTU communications module located in the PLC rack, which polls each of the intelligent electronic devices concurrently. This configuration allows all the data to be collected and stored in one location for outside devices to read and has the added benefit of limiting the amount of communications traffic to the intelligent electronic devices. In addition to providing the data to outside systems, the PLC also parses the data to be sent to the pipeline's central SCADA system. As per the pipeline's goals, the new system must provide a mechanism to prevent remote configuration changes without station personnel consent. Therefore, a physical local selector switch was installed and configured for each protective relay. The switch must be placed in the "Enable" position and the remote user must also utilize a location specific access code to enable configuration changes in the device.

1) *Network:* The network architecture had to be fault tolerant to meet the system's goals and objectives. Figure 2 details a typical network arrangement. See Appendix A for enlarged Figure 2. Due to the independent nature of the pipeline's station configuration (multiple lines of equipment), the project selected fiber optic Ethernet rings with the Rapid Spanning Tree Protocol (RSTP) enabled. The ring would consist of each intelligent electronic device that supports the ring and have at least one connection to the pipeline's existing station Ethernet network via copper CAT5 cable. All devices that do not support the ring architecture are connected to the ring as "spurs" off the ring. In some cases, those devices had a secondary connection, which was attached to another part of the ring. At pipeline locations with multiple "lines" of equipment, the two fiber rings were connected via fiber optic

cabling. This extra fiber connection allows for another level of fault tolerance.
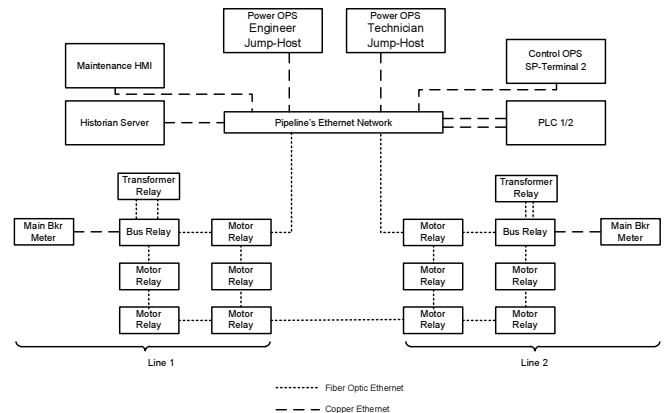

Fig. 2 – Typical Network Architecture

2) *Monitoring*: To meet the pipeline's objectives and goals for the project, the new devices' data must be available both locally and remotely. This goal was a simple one to meet when considering the prior decision to make the PLC the central location for the system data. The more difficult hurdles were the pipeline's interpretation of Cyber Security requirements and procedural requirements that prevent technician remote control access. Due to these requirements, two new computers were installed at each location. The first computer, called the "Historian Server" was placed on the same network as the PLC equipment. The Historian Server is allowed direct access to the PLC via the communications network and runs two separate server packages: Historian and HMI. Both software packages communicate via a common OPC (OLE for Process Control) server. The HMI server tag database was configured with read-only tags. The Historian Server is physically installed inside an electrical panel, with no keyboard, mouse, or monitor. The second computer, called the "Maintenance HMI", was placed on a new virtual local area network (VLAN). This computer was granted communications access to the Historian Server, but only on the Ethernet ports/protocols utilized by the required software packages. The pipeline only communicates to the server via the HMI and Historian software packages, all other communications traffic between the two computers is not allowed. The Maintenance HMI computer is physically located at the station in an electrically safe area (outside of Arc Flash boundary) and has a keyboard, mouse, and monitor so that it can be accessed locally. The Maintenance HMI is available to any and all company personnel at the station. The HMI package installed on the computer follows the pipeline's "style guide" for HMIs and therefore provides an interface to which the technicians and engineers are familiar and comfortable. The Maintenance HMI which is accessible by technicians and engineers polls all motor, bus and transformer protective relays and collects event data. Additionally, the engineers and technicians have a "jump-host" they can log into at the corporate level, which will allow them remote access to the station's Maintenance HMI. The engineers and technicians have been given formal training and can access the station's data from anywhere. The pipeline engineers have an additional jump-host they can

access which will allow them to directly communicate with the intelligent electronic devices via the vendor's software package. This allows a higher level of diagnostics capability such that oscillography fault data can be retrieved from protective IEDs. However, as discussed above, no configuration / setting changes on any protective relay at the station can be made without station personnel enabling programing access and a location specific access code entered by the engineer.

IV. LESSONS LEARNED

This application involves pumping stations that are approximately every 30 miles between Houston, Texas and Linden, New Jersey. The first assumption made was that most of the pumping stations would be identical, since they had similar number and horsepowers of motors. A lab was created to duplicate what would be installed in the field. See Figure 3 of the pipeline's lab set up. The lab cost was less than 1% of the overall project's upgrade costs. Creation of the lab helped find a number of issues before field installations, such as communication/network issues, process vs. protective relay lockout/operation and overall new scheme design. A lab is also a great tool for training personnel. Once field installations commenced it was found the installations were not identical. In addition, the lab allowed development and testing of protective relay settings/configuration templates that would be used as a starting point for each station. Vendor PC software for the protective relays was used to document, monitor and troubleshoot programmable logic used in the project.

Fig. 3 – Pipeline's Lab

The objective of this project was to reduce the arc flash hazard level to personnel. Actual measured operating time for a bus fault was 54 ms using the oscillography capability of the bus relay. Prior to low impedance bus protection installation, the operating time for a bus fault was approximately 600 ms including breaker operating time. The project was able to reduce the arc flash levels from category 4 to category 1 or 2 depending on the installation.

A major lesson learned was that "everything takes three times longer than it should". It is recommended to select a known contractor that has the necessary installation and testing skills. One example during installation was that a stray voltage was found where it should not have been. It took two hours to solve the problem. Wiring in general took much longer than anticipated. Some wires marked on drawings could not be found in the field and some wires in the field were not on the drawings. As a result, the pipeline decided to have protective relays and external devices pre-wired and mounted on panels/doors off-site prior to installation which allowed quicker on-site installation.

Another lesson learned was "what you think is there may not be". Part of the scope of this project was to replace the class C20 current transformers with class C100 current transformers, to reduce CT saturation. At one station, the existing CTs were not located in the back of the switchgear as expected, but had been installed on the bus stabs. The replacement CTs window size purchased would not fit over the bus stabs. It is strongly recommended that a complete site visit be conducted prior to design and installation. Switchgear should be shut down and opened. Hundreds of pictures should be taken to document everything at the station.

A lesson learned was that the manufacturers recommended settings to be put in the protective relays did not agree with the company's historical design settings. Using the data from the digital protective relays event recorder and oscillography allowed fine tuning of the protection settings. Multiple discussions occurred regarding the proper setting. This is a great example of the fact that relay settings are an art as well as a science.

When designing the system, one needs to determine how to handle alarm indications. A very short intermittent alarm may not be picked up by SCADA. It was decided all alarms must be maintained for at least 10 seconds, so SCADA could detect them. Thus, where necessary, timers were added within the protective relays.

Another lesson learned was that testing all the related components should have been given more attention during the design phase. Digital Protective Relays, Programmable Logic Controllers (PLC), Process Control, and Historian HMI devices talking and working with each other is recommended to be in the lab. Since the PLC, HMI and process control components were not available, these system tests were not performed in the lab prior to first installations. It is very difficult to do a complete "system" test before installation; however this would have saved substantial time if these tests were completed prior to installation versus having to do the work in the field, which increased the outage time on the first installations.

A set of construction drawings, including demo drawings, needs to be at the job site. Changes that are found on these drawings must be noted in detail for future projects. An important lesson learned was that detailed punch lists are necessary on all projects to make sure all task are completed and tested.

Damaged components occurred on the project due to the fact both 208 VAC and 48 VDC are in the same cabinet. It is recommended that the wiring for different voltage levels be different colors. UL 508A states that blue insulation should be used for 48 VDC. The original gear manufacturer used black.

Issues resulted from using old equipment at the stations was experienced in the project. It is recommended to have the necessary new equipment required and sufficient spare new equipment during startup to avoid additional outage time. The microprocessor based protective relays used in this project

have modular construction which aided in quick resolution of any hardware issues. For example, a fiber optic port was damaged on a protective relay and the module was replaced quickly rather than having to completely re-wire another protective relay.

V. CONCLUSIONS

Utilizing microprocessor based relays allowed the pipeline to achieve their objective of lowering their incident energy for arc flash from category 4 to category 1 or 2 depending on the installation. In addition to this goal, several other benefits were gained by utilizing the full function of the relay as an IED, such as monitoring and diagnostics. This functionality was an inherent benefit because the IED had the capability. It was merely a matter of enabling the IED and developing protection and control schemes that utilized the full benefit of the IED with the goal to reduce unnecessary equipment. IEC61850 standard enabled the reduction of wiring and advanced communications. A fault tolerant and secure communications network allowed advanced control by PLCs, maintenance HMI and corporate network. The lessons learned in this project aided the pipeline throughout the design, installation and operation phases of the project.

VI. REFERENCES

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[4] *B90 Low Impedance Bus Differential System Instruction Manual*, GE Publication GEK-113612.
[5] *T35 Transformer Protection System Instruction Manual*, GE Publication GEK-113627.
[6] *Hard Fiber Process Bus System Instruction Manual*, GE Publication GEK-119595.

VII. VITA

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John Levine, P.E., a native of Birmingham, Alabama received his Electrical Engineering degree from Georgia Institute of Technology in 1976. His career started with Square D Company as a Field Engineer. In 1981, he accepted a position as Product Manager for GTE Sylvania at the Clark Control division in Lancaster, SC. After several promotions and a corporate buy out, he was promoted to National Sales Manager of Joslyn Clark Controls. In 1984, Mr. Levine started Levine Lectronics and Lectric, Inc. an electrical manufacturer's representative company. He is a senior member of IEEE and is active in the IAS, PES, and the IEEE-IAS Pulp and Paper committee.

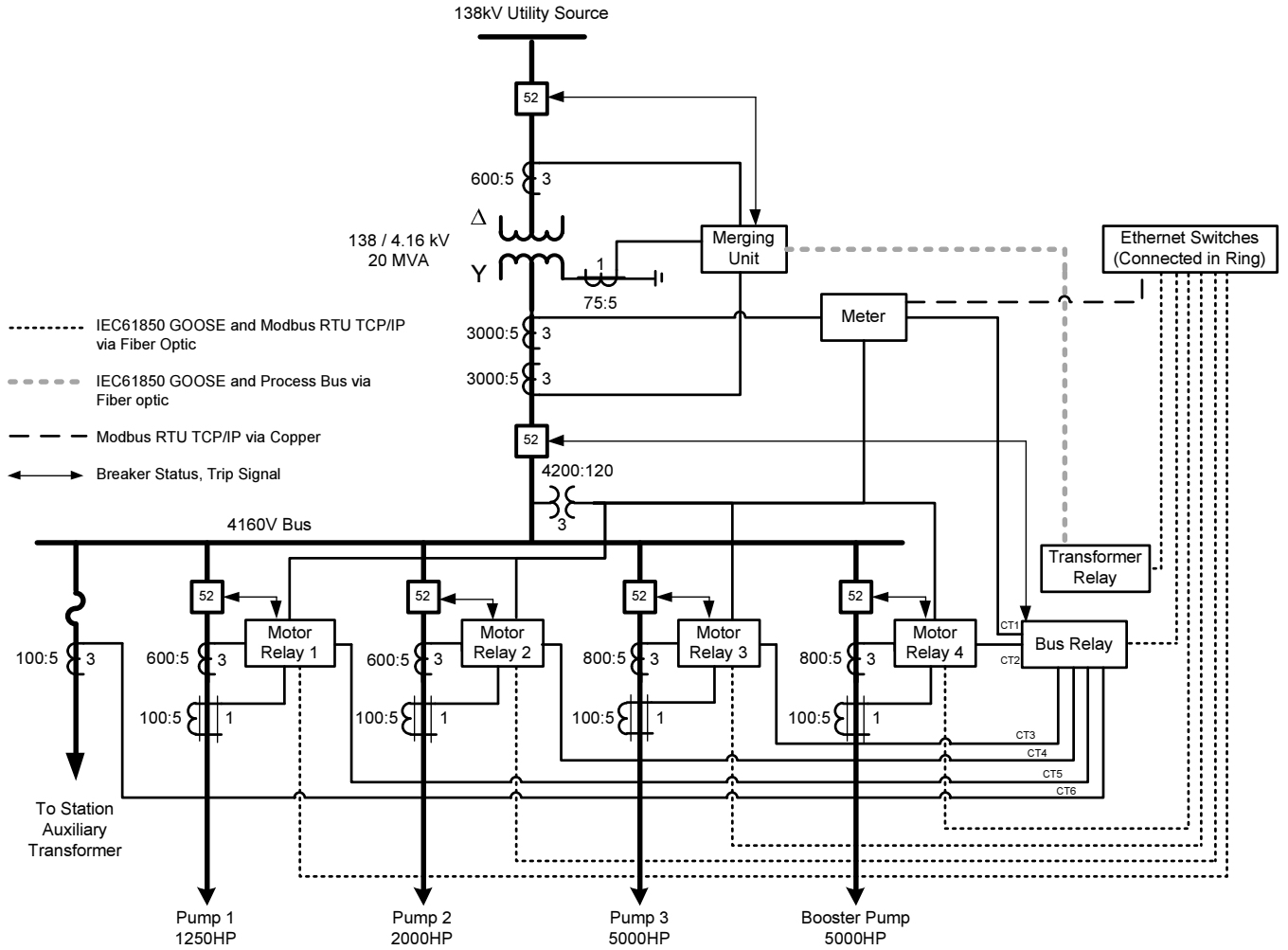# APPENDIX A

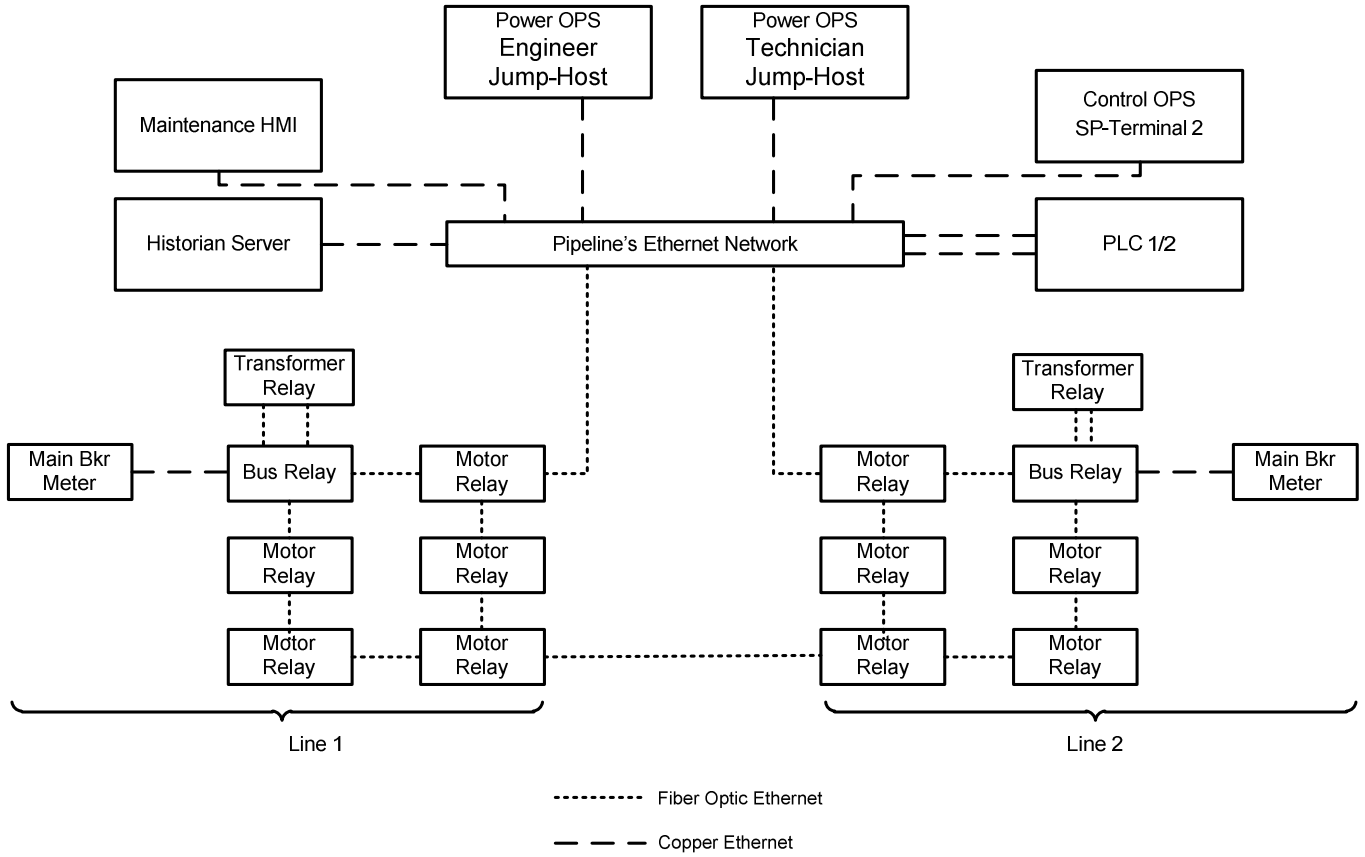## LARGE FORMAT IMAGES OF FIGURES 1 AND 2

Fig. 1 – Station Protection & Control One-Line

Fig. 2 – Typical Network Architecture