Integration of Site Generation With Automated Electric Distribution Loops for Reliable Power at the University of Iowa Research Park

Stephen Hoffman
University of Iowa

David Charles
Shermco Industries

Mike Dood
Schweitzer Engineering Laboratories, Inc.

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***Abstract*—The University of Iowa Research Park satellite campus has historically operated with a 7,200 V overhead system. New facilities with stringent power reliability targets, including a critical health and research facility and a new data center, highlighted the need for increased power capacity and reliability. The University of Iowa combined the backup power requirements of the Research Park with its own stated intention to develop renewable energy, culminating in the Oakdale Renewable Energy Project.**

The centerpieces of the project are two 1.4 MW natural gas engines that may also be operated on low Btu (e.g., landfill) gas. This development also resulted in the installation of an automated 13.8 kV loop electric distribution system with centrally located standby generation. The underground 13.8 kV system used relatively inexpensive pad-mounted switches installed at each building transformer to sectionalize the loops. Instead of programmable logic controller-based controls for the gas engine generators, 13.8 kV switchgear, and pad-mounted switches, the university utilized programmable multifunction relays for system control and protection. The same relay model was used for control and protection of the generators, main and feeder circuit breakers, and remote pad-mounted switches serving loads. The communications function is implemented by fiber using Ethernet technology.

The overall project required automating switching and coordinating the loop circuits supplying campus loads, the control and operation of on-site generators supplying power to each loop bus, and the control and automation of power supply switching—all integrated into a supervisory control and data acquisition (SCADA) system, with a human-machine interface (HMI) for the operators.

Typical of any large institution, a project of this scale required the cooperation of many university departments. Choosing equipment, determining the appearance of the HMI displays, and coordinating the construction effort were accomplished based on participation and input from stakeholders. The work was divided into several construction contracts running simultaneously, with each contract fulfilled through the work of multiple contractors. Those familiar with this scale of effort may appreciate that the satisfactory operation of the communications medium alone is a significant accomplishment.

The installed system was performance-tested live when the power supplier experienced outages on a very hot day in July. To the delight of the designers, construction management, and operating personnel, the system worked perfectly the first time. This paper reveals the process of how this was accomplished.

I. Conceptual Design

The University of Iowa's established goal to be a leader in renewable energy strategies and sustainability practices evolved into the formation of the Oakdale Renewable Energy Project. The central strategy was to utilize cogeneration to provide electrical heat and power to campus facilities in a highly efficient manner. The equipment was to use natural gas and alternative and renewable energy sources, such as biomass, landfill gas, or anaerobic digester methane, as they became available. Any of the fuel sources would satisfy the requirements of new facilities constructed at the satellite campus. The University of Iowa Research Park campus provided a greenfield site for development of alternative energy strategies. The concept became reality when the university, supported by professional design consultants, awarded a contract to acquire two 1.4 MW natural gas or low Btu (e.g., landfill) gas-fueled, spark-ignited engines with heat recovery equipment.

Along with a new cogeneration facility came the attendant campus infrastructure requirements of a hot water heating distribution system, a chilled water cooling distribution system, and a campus electric system capable of distributing necessary power. Consequently, a large-scale, multifaceted project was under way, requiring multiple university project managers, several design firms, and a number of construction firms.

II. Project Impacted by Historic Flood

In June 2008, the Iowa River exceeded what was thought to be the 500-year flood level and inundated portions of the main campus along both banks of the river. This happened despite the campus being downstream of a very large reservoir. The flood and resulting damage were of such historic proportions that a number of news organizations and politicians came to view and assess the damage. The main campus power plant filled with water and was disabled for months. Damage was also sustained to 20 buildings.

The Research Park facilities were not directly affected by the flood and were no longer the main focus of university resources. Even though contracts were signed and construction was under way, the university turned to the crisis at hand.

Typically, a major disaster would have delayed a renewable energy project, but commitments had been made to install electricity and heating in new facilities under construction.

Those familiar with large-scale institutional endeavors, where decision making is often accomplished in a committee environment, appreciate the conflicting requirements that often beset any large-scale project when the need for detailed decision making is required. Everyone appreciates the need to plan ahead, but for what are we planning? Decisions about how to control the gas engines and integrate site generation into the electric distribution system needed to be made. What equipment should be purchased, what control systems come with purchased equipment, and how should the human-machine interface (HMI) be developed? What level of automation should the control system support? How would the interconnection with the local utility company work?

Despite the diversion caused by the flood, the project team arrived at the following decisions:

- The selected engine was available only with a 4,160 V generator. The original plan called for a 4,160 V generation bus with ties to either side of the 13.8 kV bus through large step-up transformers. Instead, each generator was unit-connected to its own step-up transformer and 13.8 kV circuit breaker. Unit-connected generators reduced the amount of switchgear (and cost) and greatly simplified the synchronizing requirements.
- The university standard and preferred protective distribution relay was a digital multifunction programmable relay, with generator protection provided by a specially designed generator digital programmable relay. Instead, more capable digital programmable relays were selected. The new capabilities included expanded programming capabilities, Ethernet communication, and IEC 61850 protocol for exchange of information between multiple relays. Rapid and reliable transmission of status information between relays was a key benefit of the IEC 61850 protocol. This protocol also allowed the set of exchanged variables to be defined later in the project, as more details became available about other control systems.
- The digital multifunction relay would serve as a relay protection and automation platform for all locations, including the main utility feeds, power plant auxiliary power, generator protection, loop protection, and building switchgear protection. The selected relay had sufficient hard-wired status I/O to allow an interface with a number of systems that controlled related processes within the power plant. In addition, the relay supported six current inputs and six voltage inputs, which gave it flexibility to be installed at all locations, including the building loop and transformer installation.
- Programmable logic controller-based (PLC-based) electrical switchgear controls were dropped in favor of dedicated generator controls and multifunction programmable relays. This simplified breaker control and timing issues where multiple operating systems and their attendant communications networks must be coordinated to operate in a few cycles. Wiring and point mapping were also simplified. Control logic could be developed and implemented at each local node rather than at a central processor-based PLC. Reducing the complexity of any control system by eliminating one layer of control devices always improves operation.
- The system would be automated to the greatest extent possible to enhance safety and reduce the amount of intervention required by an operator. Part of the original design criteria was to provide centrally located standby power, utilizing all sources for maximum reliability. Automated methods were necessary to meet the timing requirements and provide a consistent system response to each of the most likely system operating conditions.
- The generation units would be connected to one side of the new switchgear to support an automated bus with backup standby power and a manually operated bus, with the loop feeders connected to each bus. This had the added benefit of allowing campus loads to be supplied by the nongeneration side of the bus while the generation system was being commissioned.
- Any automated system is designed to react to defined scenarios. To maximize operator flexibility to react to developing or unexpected contingency situations, the capability to disable all automation logic while leaving the relay protection logic enabled was included. This was accomplished with pushbuttons to enable or disable automatic operation and remote control on each digital relay. Reverting back to manual operation would allow the operator to place or restore the system to the desired operating condition. An automation logic error or undesired reaction to an unanticipated system condition would also require manual intervention to the power system. The automation logic could be reviewed and corrected at a later date, after power had been restored to campus.

III. Implementation

The first step was to draft a detailed written sequence of operations for how the completed system was designed to operate. Several scenarios were identified, including the following:

- Normal status. Each 13.8 kV bus is fed by a separate feeder from the utility source, and generators are off or dispatched manually.
- Automatic 13.8 kV bus transfer. The bus tie is closed to restore power upon loss of either utility source feeder.
- Standby. The central gas generation is automatically started, and standby power is routed to intended loads after loss of utility power. Standby has several variations in field device switching, depending on the system state prior to loss of utility service.
- Automatic transfer (either 13.8 kV source or 480 V bus) at research facility load.
- Manual operation.

A. Normal Status

In normal status, as shown in Fig. 1, Bus 1 is energized from the utility through Main 1 and feeds power plant loads and both research facility transformers. Bus 2 is energized from the utility through Main 2 and feeds the remaining campus loads. The bus tie is opened to isolate Bus 1 and Bus 2, and the distribution loop is opened at Research Way 2. Each generator can be off or dispatched per economic loading.

In order to be available for automatic operations, the circuit breaker must be racked in, with automatic and remote pushbuttons enabled. In addition, the circuit breaker must not have experienced a protective relay fault operation. In this manner, an overcurrent relay operation removes that circuit breaker from the automated logic until manual intervention restores the automatic operation mode.

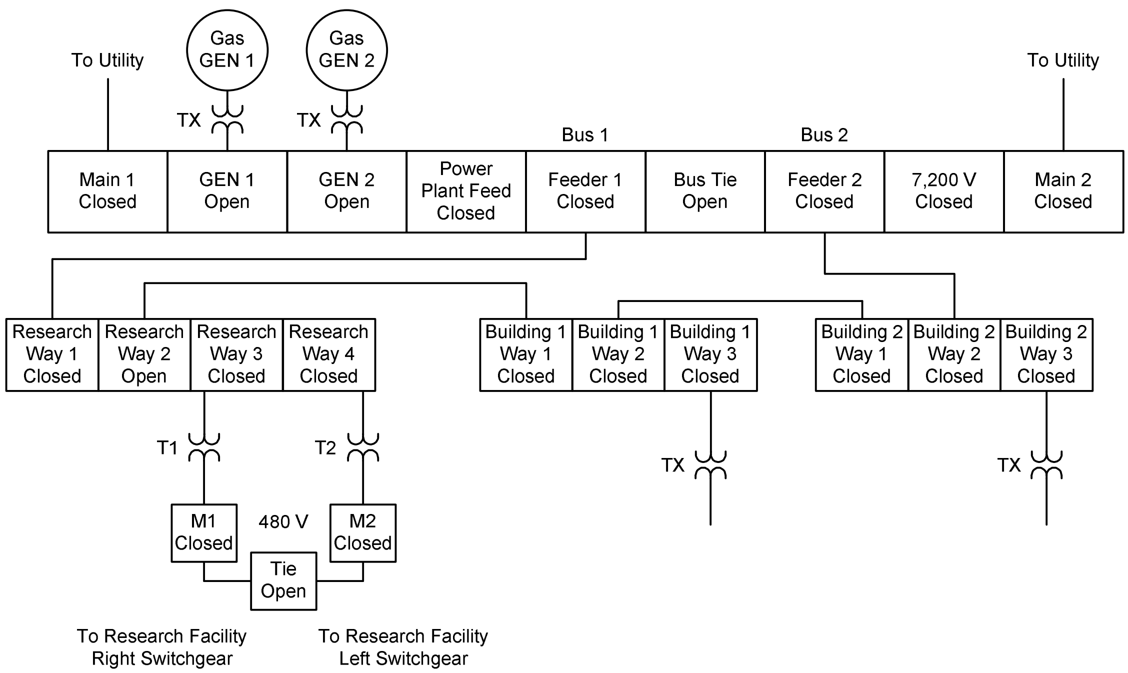

Fig. 1. 13.8 kV electric system—normal circuit breaker status.

B. Automatic 13.8 kV Bus Transfer

Automatic bus transfer was implemented to quickly recover from the outage of one of the utility feeds. The bus transfer feature is operational when Main 1, bus-tie, and Main 2 circuit breakers are in the automatic mode. The bus-tie relay has a separate pushbutton to enable or disable the automatic bus transfer logic. If the utility feed to Bus 1 is lost, the bus tie senses that Bus 1 lost voltage and that Bus 2 has voltage. After 1 second, the bus-tie digital relay directs the Main 1 circuit breaker to open and closes the bus tie, restoring power to Bus 1.

With normal status prior to this mode, the result is that the power plant and research facility lose power for 1 second and reestablish on utility power. This evolution places the system into the configuration shown in Fig. 2. Automatic transfer operates similarly upon loss of power to Bus 2, with the impact being loss of power to Bus 2 for 1 second.

C. Standby Operation Enabled on Bus 1 and Loss of Power to Bus 1 for 5 Seconds

Standby operation functions provide standby power from the centrally located generators to specific campus facilities in an automatic fashion. The standby feature is operational when Main 1, Main 2, power plant, and distribution feeder breakers are available for automatic operation. In addition, each generator must satisfy a series of conditions to be available. These conditions include circuit breaker is racked in, unit is not blocked from standby via pushbutton selection, automatic and remote are enabled, generator is not in stopped or e-stop mode status (as indicated by generator control system), and communication is okay to remote status I/O blocks. In addition, the circuit breaker must not have experienced a protective relay fault operation. In this manner, an overcurrent or differential relay operation removes that generator from the automated logic until manual intervention restores the automatic operation mode.

The standby process begins when Bus 1 loses power to the line and bus side of the same phase voltage for 5 seconds. This method for detecting a power outage protects from triggering the standby mode if a fuse is lost on one potential transformer. The Main 1 digital relay subsequently enables the standby mode, which triggers the following:

- Main 1 opens.
- GEN 1 starts, if available.
- GEN 2 starts, if available.
- Power plant feed opens.
- Feeder 1 breaker opens, if available.
- Bus tie stays open, if already open.
- Feeder 2 breaker opens, if the bus tie is racked in.
- 7,200 V breaker opens, if the bus tie is racked in.
- Main 2 opens if Bus 2 voltage is lost.
- Research facility digital relay opens Way 2, and Way 3 de-energizes T1. Way 4 stays connected to T2.

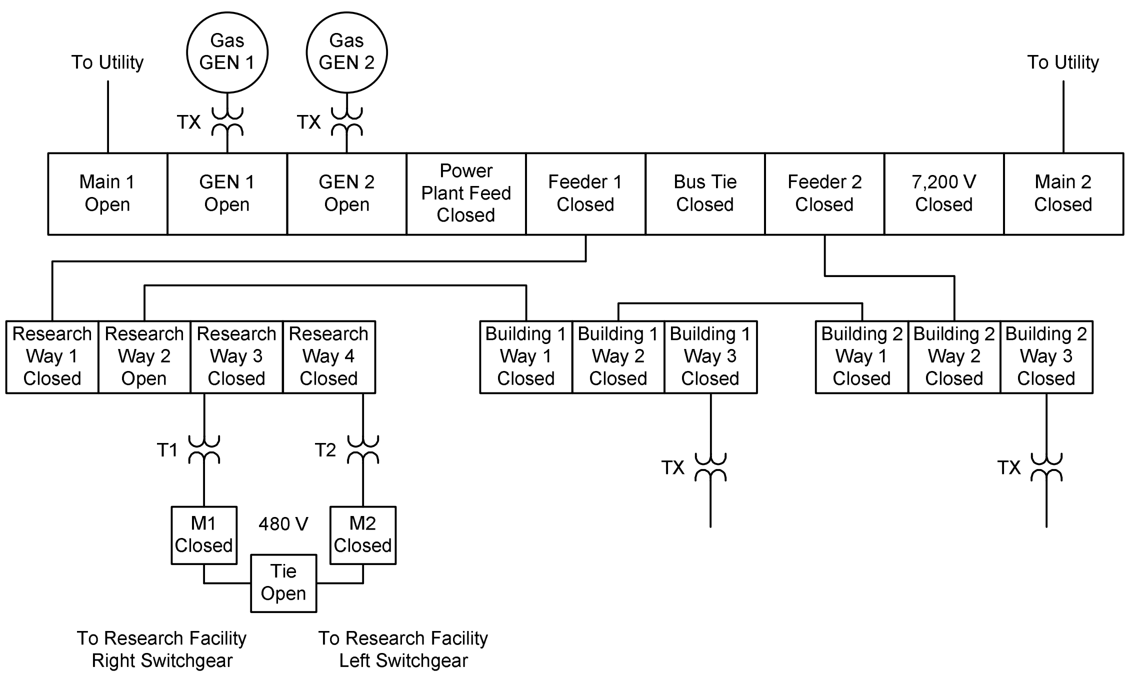

Fig. 2. Following a Bus 1 outage, the bus tie closes after 1 second to pick up Bus 1 loads from Bus 2.

The system is now in an interim operating condition, as indicated in Fig. 3. As standby operation continues, the following occurs:

- Generator request to start is maintained until the unit either starts, becomes unavailable, or standby ends.
- Once the first generator starts and builds voltage, its circuit breaker closes to energize Bus 1.
- Power plant feed closes to restore power to the power plant as soon as the first generator energizes Bus 1.
- Second generator starts and synchronizes to Bus 1.
- Feeder 1 closes after both units come online or 120 seconds into standby if one unit is online. Once the Feeder 1 circuit breaker closes, power restores to Bus 2 and the left half of the switchgear inside the research facility.
- Bus tie closes if Main 1 and Main 2 are open.
- After a 60-second time delay, Research Way 3 closes to energize T1, which restores power to the 480 V Bus 1 and the right half of the switchgear inside the research facility. The 60-second delay is included to allow time for the building to sequence on loads in blocks to match generator loading capability.

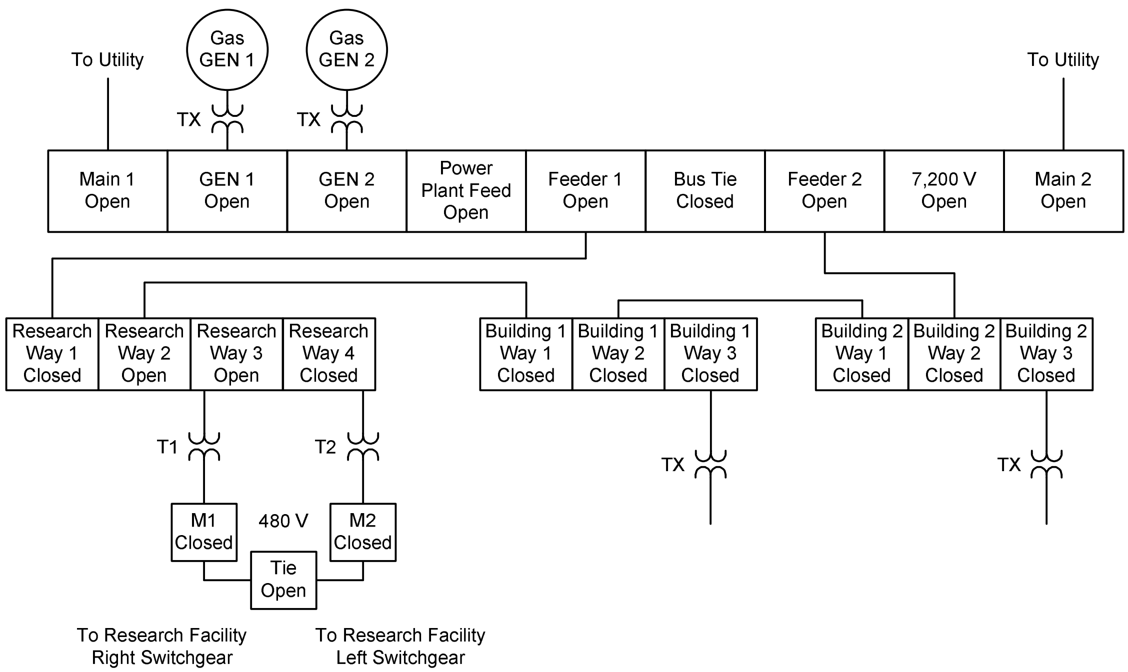

Fig. 3. Bus 1 loses power for 5 seconds; standby starts and clears Bus 1 and Bus 2.

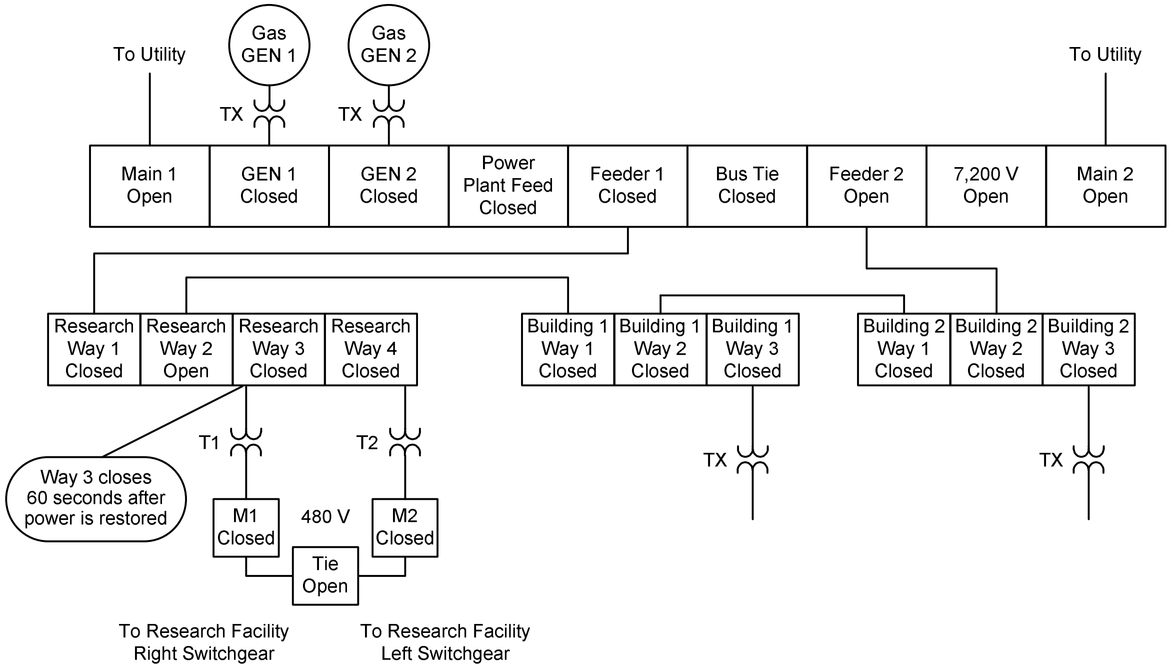

Fig. 4. Standby starts GEN 1 and/or GEN 2 with power to the power plant and research facility T2; 60 seconds later, power is restored to T1.

Standby operation on the generators continues with the system in the configuration shown in Fig. 4. No other load or circuits are restored through the automatic standby logic. If the generators are deemed to have sufficient capacity, manual operation can be used to energize additional loads.

After the utility restores power, standby is ended by either of the following:

- Synchronize back to the utility via a closed transition when the {RETURN TO MAIN 1} pushbutton is pressed on the Main 1 relay or via HMI.
- Synchronize back to the utility via a closed transition when the {RETURN TO MAIN 2} pushbutton is pressed on the Main 2 relay or via HMI.

After synchronizing to the utility, the generators are sent a stop signal and their circuit breakers open. Manual operation is then needed to restore the system back to normal conditions and power to the campus facilities.

D. Standby Operation Enabled on Bus 1 and Loss of Power to Bus 1 for 5 Seconds With Bus Tie Racked Out

During project implementation, a method was needed to limit the scope of operations to Bus 1, while Bus 2 continued to be fed from utility power. This mode was initially set up to allow outages during testing on Bus 1, while construction power continued to be fed by utility power via Bus 2. This mode was retained because it was an easy way to set up an automatically operated bus and a manually operated bus. This mode continues similar to the standby mode discussed in the previous subsection, except that Bus 2 loads stay connected to the utility during the outage and are re-energized as soon as the utility source returns.

E. Standby Operation Enabled on Bus 1 and Loss of Power to Bus for 5 Seconds With Main 1 Out of Service

This mode is necessary in the event that the Main 1 utility feed is out of service. The automatic standby operation must be functional even when the Main 1 digital relay is not available. In this mode, the Main 2 digital relay drives the standby process because Main 1 is not available. The distributed logic operates similar to that shown in Section III, Subsection C.

F. Standby Operation—Feeder 1 Not Available or Racked Out With Power Fed Through Feeder 2

In the previous cases, the Feeder 1 circuit breaker has the priority to operate to restore power to the research facility. If the Feeder 1 circuit breaker is open and not available, then the Feeder 2 circuit breaker closes to restore power to the research facility.

Under this scenario, Research Way 1 and Research Way 3 open upon the start of standby operations and Research Way 2 closes if it is open. When power is restored from Feeder 2, T2 is energized, and 60 seconds later, T1 is energized. To prevent generator overload in islanded operation, the transformer Way 3 is opened at the other buildings on the loop.

G. Loss of Single Transformer at the Research Substation

The same digital relay was installed at the remote building substations to monitor status and control the breakers in the pad-mounted 13.8 kV switchgear. At the research facility, the same digital relay also operates the 480 V transformer and bus-tie circuit breakers. Logic was included to detect the loss of a single transformer, whereupon the affected transformer is switched off, and service to the building is restored by closing the bus tie.

H. Loss of Primary Distribution Feed at Research Substation

If a fault occurred on the cable between Bus 1 and the research facility under normal operations, the Feeder 1 circuit breaker would open to clear this fault. This results in a loss of power at the research facility T1 low side and T2 low side. The digital relay at the research facility detects this condition and, provided that Feeder 2 is closed, restores power by opening Way 1 and closing Way 2.

IV. Distributed Control and Interface With Other Control Systems

The conceptual design called for a PLC development to match engine generator operation with hot water production and electrical generation requirements. The operational requirements were only generally defined at this stage, so specific details of how the system would work were left for the installation phase. Instead, the majority of the automation logic was implemented in the programmable multifunction relays, which were already installed to control circuit breaker operations and generator control. The primary goal of this decision was to have one operating platform and one communications network that could be accessed or programmed by anyone familiar with the chosen technology. The installed system was going to have digital multifunction protective devices, and university operating personnel were already familiar with the programming and communications requirements. The key feature was to have a control system accessible to the end users, without the requirement of specialized skills beyond those required for maintaining the digital protective relay system.

The gas engines were provided with a proprietary control system interfaced through hard-wired digital contacts and analog I/O. Table I shows an example of this interface description, where it was ultimately discovered that “demand” meant “request engine to start.” Terminology and definitions were confusing and presented a challenge during project design and implementation.

TABLE I
ENGINE CONTROL INTERFACE EXAMPLE

No.	Description	From	To	Contact Type
14	Status: ready for automatic demand	Engine controls	Customer	One no contact closed = ready
15	Demand module	Customer	Engine controls	One no contact closed = demand

The interface between the engine controls and the generator relay installed in the 13.8 kV switchgear is accomplished with two remote I/O blocks utilizing a fiber connection. Exchange of information is accomplished with a proprietary peer-to-peer communications technology. Table II lists the mapping that the first remote I/O block uses between the digital relay and the generator controls.

TABLE II
REMOTE I/O BLOCK 1 MAPPING TO GENERATOR CONTROLS

Transmitted and Received Bits	Local Variable Name	Generator Control Function
TMB1A	PLT01	Stop generator
TMB2A	PSV01	GEN 1 available
TMB3A	1	Natural gas
TMB4A	CCIN002 or CCIN006 and CCIN082	Mains closed
TMB5A	PLT14 or PLT15	Return to 52-1 or 52-13
TMB6A	IN101	CB 52A
TMB7A	TMB5A and PCT02Q	Engine slow
TMB8A	TMB5A and PCT03Q	Engine fast
RMB1A	PSV33	GEJ controls in auto
RMB2A	Not PSV34	Open = e-stop
RMB3A	Not PSV35	Open = general trip
RMB4A	Not PSV36	Open = grid fault
RMB5A	PSV37	Close GEN breaker
RMB6A	PSV38	Open GEN breaker
RMB7A	PSV39	General engine alarm

Engine generator control is implemented with operator pushbuttons driving protection logic to start and control the engines, as shown in Fig. 5. The gas engine controls provide engine control, voltage regulation, and synchronization. The digital relay-based controls start and stop the units and indicate parallel or isolated operation. The digital relay also provides basic generator protection, supplemented with a standalone digital current differential relay for protection of the generator and step-up transformer. The system normally remains in standby power mode so that a loss of source potential starts the engines, energizes the bus, and feeds power to the research substation. Breaker control is implemented through communications bits, with logic in each digital multifunction relay that determines the appropriate action.

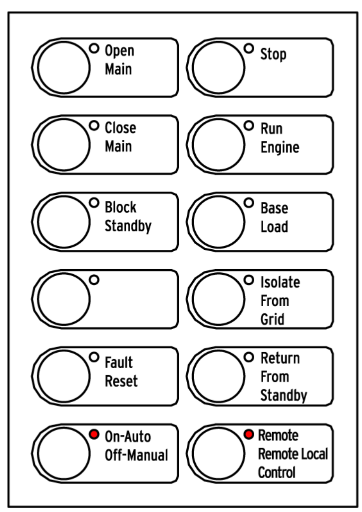

Fig. 5. Generator control pushbutton arrangement.

The {AUTO} pushbutton enables automatic control and determines the availability of a circuit breaker to participate in automatic operations. Certain key circuit breakers, such as the main breaker on the bus, must be in automatic mode for a standby operation to take place. Taking the digital multifunction relay out of automatic informs all the other relays that a breaker is not available and sets up the system for manual operation. The {REMOTE} pushbutton allows remote operation of the circuit breaker in coordination with the automatic operating scheme. The circuit breaker protective trip function is active in all operating modes, but enabling local control permits a local circuit breaker to close for a manual operation. The control logic allows local operations while still providing protective settings and synchronism-check functions. These two functions also allow a local operator to put the system in manual control to restore power in the event that automatic operations fail. By disabling both pushbuttons, all circuit breaker operations are restored to the local operator and all automatic breaker operations are blocked.

The {FAULT RESET} pushbutton is used to unlatch certain relay protective functions, take the protection logic out of automatic, and reset protection latches and operating sequences. In other words, a relay protective function will trip the circuit breaker, disable the automatic operation logic, unlatch the {AUTO} pushbutton, latch the system fault function to prevent a breaker close operation, and notify the other devices that the circuit breaker is unavailable. The {FAULT RESET} pushbutton must be pushed to unlatch the fault. The {AUTO} pushbutton may then be restored to automatic, and the circuit breaker is again available. To the extent possible, the protection logic in each digital multifunction relay adapts to the loss of any circuit breaker. A generator breaker or feeder breaker can become unavailable during an automatic sequence of operation without causing a breakdown of the controls or an undefined state of operation. To accommodate the loss of the main or tie breaker, racking the breaker out of the cell supports predefined operating modes that recognize that the breaker is open and not available for operations. The racked-out condition can be treated differently than a breaker-unavailable condition.

Loading control is provided by a digital engine governor controller device that generates a kilowatt loading signal as an input to the engine controls. Governor devices are installed on all generator breakers and utility power connection circuit breakers to allow the development of future control scenarios. The possible future requirement to share load between generators of different manufacturers or change the manner in which power flows between the utility interconnection led to the inclusion of the digital generator governor control product. Synchronizing generation with a main-tie-main switchgear arrangement has always been problematic. Load sharing between generators of different manufacturers is often problematic. For example, the gas engine controls can share load, but only with other identical control systems. The selected series of governor devices supports individual generator and tie-line control and will control many types of generators to provide future flexibility.

V. HMI and Control System Integration

The entire plant system is integrated into the university supervisory control and data acquisition (SCADA) system, with an HMI for the operators, as shown in Fig. 6. The digital relay devices are connected with serial connections to the communications processors. Inside the power plant, the balance of the plant and heat recovery system is monitored and controlled by a PLC and is integrated into the SCADA system. The gas engine controllers are connected via an open connectivity link over Ethernet to allow display of engine sensor information. The generator governor controllers are also linked to the SCADA system. A separate building control system serves to control ventilation fans and is also integrated into the overall control system.

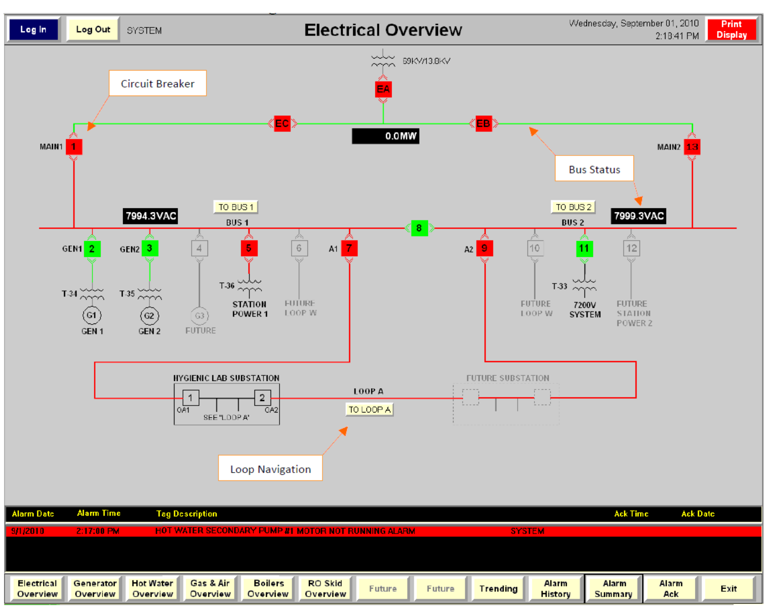

Fig. 6. HMI electrical overview diagram.

The plant operators have access to, and control of, all operating equipment through the HMI developed by a system integrator. The operation of the power plant is tied back to the university main power plant for remote monitoring and control when the plant is unattended. In addition, the power plant and research substation 480 V switchgear is connected through a gateway to the Ethernet network. The challenge with SCADA development is to effectively select from too much information to present the best, most concise view of system operations. HMI development avoided operator overload by careful selection of items to display on each screen. Colors are used to indicate energized status.

Word bits and analog values are obtained by the HMI from the communications processor. Point lists were developed from the status points shared over the relay IEC 61850 communications network that was implemented on a separate virtual local-area network on the Ethernet network [1]. To simplify the point list and obtain continuity between relays, the decision was made to assign word bits to front-panel display light-emitting diodes (LEDs) so that the relay front panel corresponded to the HMI. This had the distinct advantage of simplifying point mapping for the relay front panel in the field and in the HMI. The HMI developer was provided with the list shown in Table III and the communications processor address for each relay display LED.

A heartbeat was implemented to monitor the IEC 61850 communications status between relays. A variable was created that changed state every 5 seconds, and this variable was published by the relay. Subscribing relays that depended on communication with the publishing relay for correct logic operation monitored this heartbeat. These receiving relays would disable the automatic mode of operation if the heartbeat went missing for a defined period. The decision was made to utilize manual restoration of the automatic mode. For example, the utility main feeder relay was taken out of automatic mode if it lost communication with both generator relays (i.e., there is no way to start engines automatically if this communications link is lost).

TABLE III
FRONT-PANEL LED MAPPING FOR MAIN RELAY

Word Bit	Description	Assignment
51S1T	Time-overcurrent trip	LED 1
5152T	Ground fault trip	LED 2
67P17	Reverse power trip	LED 3
PLT05	Fault set	LED 4
PLT06	Automatic/manual switch position	LED 5
PLT12	Remote/local switch position	LED 6
PSV01	Breaker available	LED 7
PSV02	Synchronism check	LED 8
PLT14	Standby power operation	LED 9
	Not used	LED 10
PLT08	Isolate operation	LED 11
PLT07	Return to normal power	LED 12
TLED13	Bus Phase A voltage good	LED 13
TLED14	Bus Phase B voltage good	LED 14
TLED15	Bus Phase C voltage good	LED 15
TLED16	Line Phase A voltage good	LED 16
TLED17	Line Phase B voltage good	LED 17
TLED18	Line Phase C voltage good	LED 18
	Not used	LED 19
	Not used	LED 20
	Not used	LED 21
IN201	Trip circuit monitor good	LED 22
	GOOSE communications fail	LED 23
TLED24	System clock (IRIG-B) good	LED 24

VI. Testing and Commissioning

Typical of any power delivery system—even one under construction—power outages become difficult to obtain once a system is energized. The new research facility building was under construction, so power outages would have delayed construction. Even when scheduled, the power outages required additional contractor time involvement to ensure the systems under construction successfully restarted after restoration of power. Construction of all systems had to proceed while balancing the need to test the automated system, without delaying another project schedule.

Splitting the 13.8 kV bus allowed the campus to be supplied by one bus that would remain connected to the utility source, while generator commissioning took place on the other bus. Logic development allowed a racked-out bus-tie breaker to limit automatic operations to the Bus 1 side only.

Natural gas-powered engine generators have more restrictive step-loading capabilities than a comparable diesel-powered generator. The step-load capabilities of the gas engines had to be demonstrated and the building load characteristics controlled to stay within that step profile. A 1,600 kW load bank was utilized to place load steps on the generators during commissioning. Use of a load bank facilitated testing and was essential in tuning generator performance to step-load changes in simulated power outage conditions.

The generator commissioning was an involved process, because additional information on the many measuring and control systems was obtained during construction and testing. Even with close construction scrutiny, somehow the generators were connected to the wrong step-up transformer.

The key to successful performance of the system controls was mapping the freeform protection logic in logic diagrams.

The switchgear and relays were fully documented with the typical one-line, three-line, and wiring diagrams. This left information, such as I/O functions, spread across many different pages. To facilitate review of the automation logic, the I/O functions were included in the graphical logic diagrams. Fig. 7 shows the hard-wired inputs, along with a description of what information each input reflects. Fig. 8 shows how the IEC 61850 publish variables were documented for each relay. This was also done for the remote I/O blocks that communicated using a proprietary peer-to-peer communications technology, as shown earlier in Table I.

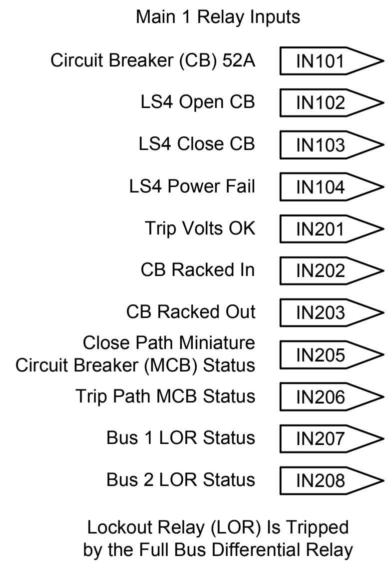

Fig. 7. This segment illustrates the hard-wired input variables for one of the digital relays.

Communications Card	Assigned To	Description
CCOUT01	PSV01	CB Available
CCOUT02	IN101	CB 52A
CCOUT03	PSV03	Line Potential Good
CCOUT04	PLT14	Standby Operation
CCOUT05	PSV08	Normal Power
CCOUT06	PLT07	Return to 52-1
CCOUT07	PLT05	Fault Set on 52-1
CCOUT08	PSV09	Loss of Bus 1 Potential
CCOUT09		
CCOUT10		
CCOUT11		
CCOUT12	IN203	CB Racked Out
CCOUT13		
CCOUT14		
CCOUT15		
CCOUT16	PLT32	GOOSE Communications Pulse

Fig. 8. This segment illustrates the IEC 61850 output variables for one of the digital relays.

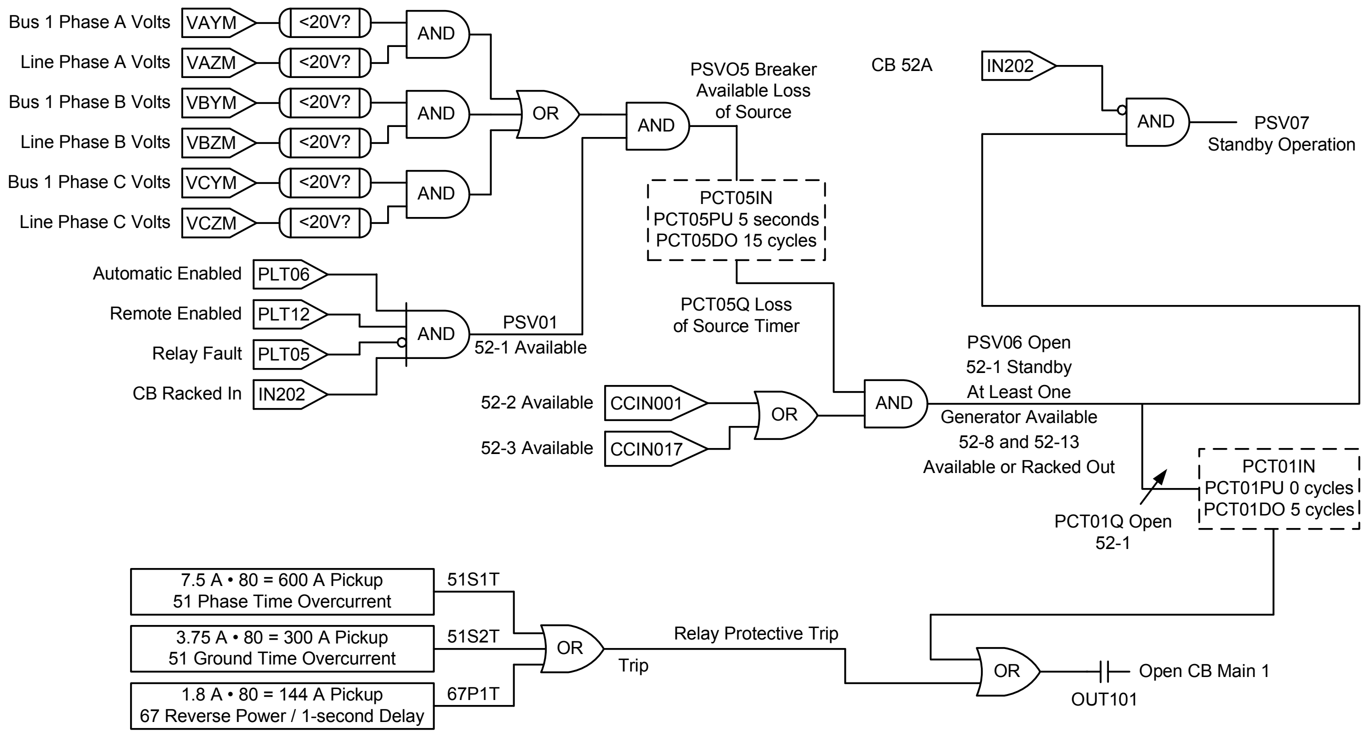

Fig. 9. Example of a logic diagram. This segment initiates standby operation to open circuit breaker Main 1 when the breaker is available and voltage is lost on the same phase for 5 seconds. This is a small example—logic diagrams were developed and reviewed for the entire automation logic as a quality control measure.

The automation logic was documented in logic diagrams for all of the digital multifunction relays. An example of this mapping is shown in Fig. 9, which shows how the protective trip and standby logic funnel into OUT101, which is wired to open the Main 1 circuit breaker. The logic was developed by one engineer, and the logic diagrams were drawn and updated by another engineer. This shared review approach set up a review process, which ensured detailed review of each logic path. Logic is much easier to visualize in pictures than when looking at several lines of text.

Testing was completed to confirm proper system operation. The testing ultimately was completely end to end when the power supplier lost transmission service to the area and created an outage condition before the date of the scheduled official commissioning system performance test.

VII. Conclusions

The capabilities of the newer programmable relays present a viable alternative to a PLC for implementing complex control algorithms. This project successfully used programmable relays for a distributed generator application. The system control logic was combined with the protective relay interface in one integrated package. The timing issues of breaker control are greatly reduced by utilizing the protective relay to control the operation, without an independent control platform issuing breaker commands. Generator synchronizing takes place in cycles. Prior to the appearance of multifunction programmable relays, independent operating systems with independent communications systems and independent system clocks always made synchronization of generation systems a challenging task.

Some takeaway conclusions for those considering similar projects include:

- A seemingly simple design requirement of central, automatically dispatched backup generation meant that many things needed to be done differently than if that requirement had not existed. Selection of the appropriate control philosophy and equipment was essential to the successful implementation of this project. In the case of this project, the design and implementation was affected by the June 2008 flood.
- Using communications bits in place of hard-wired logic for circuit breaker control requires a leap of faith. The benefit is the total flexibility of programming logic. Significant changes in philosophy occurred between initial design and system commissioning. The project installation and testing gave participants a great deal of learning opportunities. Changing communications bits and programmable logic was far easier than rewiring switchgear, and it allowed the development of adaptable controls that were truly distributed among devices rather than concentrated in one controller.

- Using freeform programming logic is not as cumbersome as many believe. The key to success is developing documentation that clearly defines the desired sequence of operations. Refining the operating philosophy documentation in design is much easier than discussing the relay programming during commissioning. Do not start programming the relay until the operating sequence is completely defined and accepted.
- Investing the time and energy in developing a complete set of logic diagrams to check the programming logic is easier than finding the mistakes during startup and commissioning. The approach on this project was to first develop the freeform logic, working from the written operating sequence scenarios. Developing the logic diagrams from the relay programming was tedious, but all of the typos, the misplaced parentheses, the AND that was intended to be an OR, the wrong word bit, and the word bit that was never defined were caught. The standby power mode worked the first time, despite not yet having been tested end to end.
- Previous experience with PLC-based controlled systems indicates the necessity of maintaining a relationship with the PLC program developer. Selecting multifunction relays allowed automation and protection functions to be implemented on a common platform. This system did not require a great learning curve or hard sell for acceptance.
- The network expert for the organization is a key player in any project using Ethernet communications protocols. Even if the communications network is maintained as a separate entity, at some point the information will be accessed for another purpose, and a gateway will be opened into the peer-to-peer local-area network. Little mistakes made when setting up the communications scheme resulted in the appearance of messages in the wide-area network. Even a careless communications bit assignment can cause interesting consequences in the larger network scheme.

VIII. Reference

[1] D. Hou and D. Dolezilek, "IEC 61850 – What It Can and Cannot Offer to Traditional Protection Schemes," proceedings of the 35th Annual Western Protective Relay Conference, Spokane, WA, October 2008.

IX. Biographies

Stephen Hoffman earned his B.S. in electrical engineering from the University of Missouri-Rolla and his M.S. in electrical engineering from Purdue University. Mr. Hoffman has been employed as an electrical engineer at the University of Iowa since 2003, where he has worked on electrical relay, substation integration, and utility distribution system metering and monitor efforts. Prior to employment with the University of Iowa, Mr. Hoffman worked with Exelon for ten years, where his contributions include real-time transmission system modeling, NERC control performance standard development, and NERC interconnections operations services reference manual development. He is a registered professional engineer.

David Charles earned his B.S. in electrical engineering from the University of Iowa in 1980. Also in 1980, Mr. Charles was employed by Stanley Consultants, where he was project manager/electrical engineer in the transmission and distribution department. At Stanley Consultants, his responsibilities included engineering design of power generation facilities, industrial power plant facilities, electrical substations, switchgear selection, protective device settings and coordination, conductor selection and routing, distribution and transmission line design, SCADA and instrumentation installations, specification and selection of electric power distribution systems and utilization equipment, and load management system specification and installation. In 1996, Mr. Charles accepted a position at Energy Services Company as a project manager. His responsibilities include managing projects and services for industrial, municipal, and utility clients and providing complete solutions from conceptualization to installation for all types of energy supply, transmission, distribution, and utilization equipment and facilities. He is a registered professional engineer in the state of Iowa.

Mike Dood earned his B.S. in electrical engineering from Michigan Technological University in 1979. In 1979, he was employed by Wisconsin Electric Power Company, where he was a senior engineer in the distribution automation group. Mr. Dood's responsibilities at Wisconsin Electric included substation automation design and implementation, distribution automation, and SCADA. He also has over 15 years of experience in substation design and project management. In June 1998, Mr. Dood accepted a position at Schweitzer Engineering Laboratories, Inc. (SEL) as an integration application engineer. His responsibilities include training and assisting SEL customers in their substation integration and automation efforts. Mr. Dood is a registered professional engineer in the state of Wisconsin. He is a Senior Member of the IEEE and is an active member of the PES Substation Committee.

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