21, rue d'Artois, F-75008 PARIS
http : //www.cigre.org

CIGRE US National Committee
2016 Grid of the Future Symposium

Application of Synchrophasors and a Real-time Automation Controller for Remote Synchronization and Control of CHP-based Microgrid

S. SECREST
3C Electric

R. MONAHAN
3C Electric
USA

N. LITTLETON
Burns and McDonnell

SUMMARY

Harvard University installed a new 8 MW combustion gas turbine as part of its Blackstone Steam Plant ("Blackstone") which connects to the medium voltage campus distribution system at its primary switching station located approximately one mile from Blackstone where it also connects to the local utility. The system is designed to operate in parallel with the local utility as a conventional combined heat and power ("CHP") system under normal conditions. In the event the local utility loses power, the system is designed to separate from the utility and operate as an islanded microgrid by automatically opening the utility feeder breakers at the primary substation. In order to reconnect the campus back to the utility without interrupting power to the campus, a means was required to synchronize the campus to the utility. A control system was designed using a real time automation controller to read synchrophasor data from the protective relays on the utility feeder breakers and use this data to remotely adjust turbine speed and voltage to synchronize the campus to the utility and close the utility breakers at the primary station. The control system also transmits position of the circuit breakers in the system to provide control information to the gas turbine controls and to enable or block certain protective elements in the relays on the utility feeders. The control system also provides an automatic load shedding scheme to ensure that the gas turbine is not overloaded when operating as an island.

KEYWORDS

Microgrid, Distributed Generation, Automation, Synchrophasors, Load Shedding

ssecrest@three-c.com

Background

In 2010, the Commonwealth of Massachusetts introduced the Mass Save® program to promote increased energy efficiency by helping residents and businesses manage energy use and associated costs. Funded by a surcharge on residential and commercial electrical bills from Massachusetts utilities, the program makes funding available for combined heat and power ("CHP") plants as an electric energy efficiency for Massachusetts businesses [1]. Harvard University, being a forward thinking Institution and a steward of the environment, chose to pursue the possibilities the of CHP program.

Harvard University operates a medium voltage power distribution system consisting of several 13.8 kV circuits from Eversource and a number of medium voltage circuits which distribute power to the campus. The majority of the power to the campus is received and distributed via the Main Campus Station. Harvard also owns and operates the Blackstone Steam Plant, formerly owned by Cambridge Electric Light (now part of Eversource). Until recently, the Blackstone Steam Plant operated as a combined heat and power facility consisting of direct-fired boilers and a back pressure steam turbine that provides a source of steam for the campus as well as 5.7 MW of generation which supplies a portion of the campus load requirements.

Recognizing the potential value of expanded combined heat and power capability to further reduce power purchases, a study was initiated to assess and optimize additional combined heat and power operations on the Harvard campus. An initial screening study was performed to look at the campus as a whole, reviewing electrical and steam demand data, the existing facilities operation and loading, and the location of potential sites for the CHP based on steam and power interconnections. The study evaluated generation options which ranged from 4 to 15 megawatts based on equipment efficiency, operating costs, capital costs, and environmental and regulatory impacts. As a result of the screening analysis, a single option was selected for a detailed assessment of the overall technical, environmental and economic viability and benefits. The study concluded that an 8 MW natural gas fueled Solar Taurus 70 combustion turbine generator ("CTG") installed at the Blackstone Steam Plant was the preferred alternative for the location for the new CHP. In order to connect the new power plant to the campus distribution system, a new tie circuit was installed between Blackstone and the Main Campus station with sufficient capacity to serve the campus load from the gas turbine.

In order to connect the new power plant to the campus distribution system, a new lineup of 15 kV metalclad switchgear was installed at Blackstone to terminate the new tie circuit and to connect the new CTG to the system. Under normal operations, the new CTG is synchronized to the utility supply at the new Blackstone switchgear and operates in parallel with the local utility as a traditional CHP application. As such, the new generation was required to meet the protection requirements of IEEE 1547 [2] and the local utility interconnection requirements [3]. However, the system is designed to allow the campus to separate from the utility by opening the breakers on the incoming supply circuits at the Main Campus Station and operate as an islanded microgrid to supply the campus electrical loads from the new CTG. Since the normal operation condition for the CTG is to operate in parallel with the local utility, the microgrid required a means to reconnect the campus the utility without interrupting power. To accomplish this, a system was designed to remotely control the CTG to synchronize the islanded campus grid to the local utility at the Main Campus station.

Control System Description

The control and automation scheme was designed around the Schweitzer Engineering Labs ("SEL") Real Time Automation Controller ("RTAC"), existing and new SEL-351, SEL-311L, and SEL-700G relays, and SEL Ethernet switches, port servers, and GPS clocks. In addition, a local display and keyboard was installed at the RTAC and a remote display and keyboard was installed at the Blackstone Plant that interfaces to the RTAC via local computer and browser.

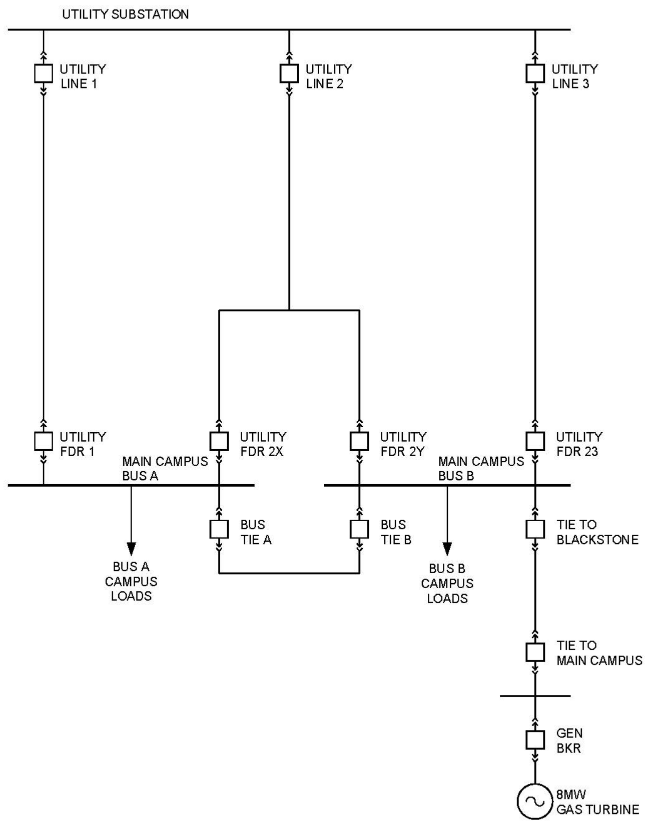

Figure 1
Simplified System One-Line Diagram

The concept for the remote synchronization scheme was based on using synchrophasors from the relays on the incoming utility supply circuits to provide the telemetry to the control system to adjust generator speed and voltage to match the incoming utility voltage. The relay protection on the four utility feeder breakers consisted of older generation SEL-351-1 relays. The firmware in these relays had capability to generate synchrophasors but did not provide the relay with the functionality to meet the requirements of IEEE 1547. Although SEL indicated that the firmware in the relays could be updated to provide the required functionality, the relays would be limited to sending only 1 synchrophasor message per second since these relays were only equipped with serial communication ports. Therefore, the line relays were replaced with current version SEL-351-7's with redundant Ethernet ports (which allows the relays to send up to 60 synchrophasor messages per second).

Remote Automatic Synchronization

Automatic resynchronization of the campus to the local utility is accomplished by synchronizing across one of the four utility feeder breakers at the Main Campus Station via the RTAC HMI. It is assumed that all three supply circuits from the utility are electrically in phase so that once the campus is resynchronized to the grid, the remaining utility feeder breakers can be closed without synchronizing although closing of each of the utility feeder breakers is supervised by a synchronism check element (ANSI device 25).

Once the operation selects one of the utility breakers to be the point of reconnection and the operator confirms this selection via the HMI, the RTAC starts the process by reading the synchrophasors from the SEL-351-7 relay on the selected breaker to determine the magnitude and phase angle of the "B" phase voltage on both sides of the breaker. The RTAC will issue raise or lower commands to the voltage regulator on the gas turbine to match the campus voltage to the utility voltage. The RTAC will also issue speed raise or lower commands depending on where the phase angle of the campus

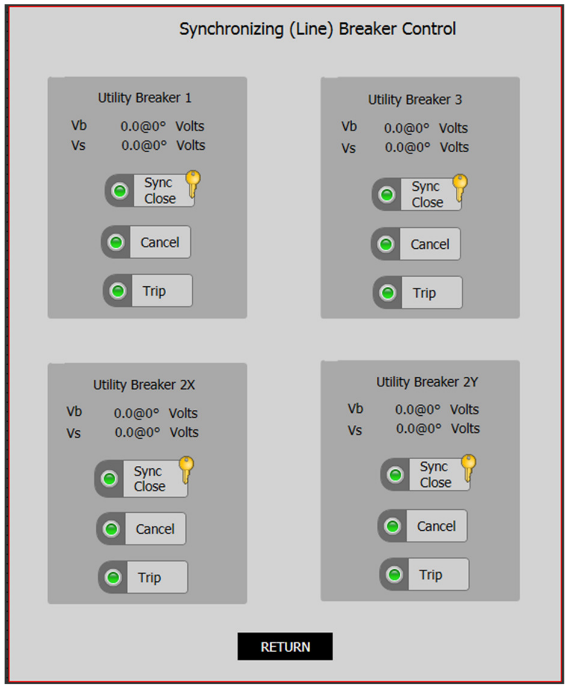

Figure 2
Synchronizing Breaker Selection Screen

phasor lags or leads the utility voltage phasor. Since it was assumed that the campus slip frequency between the campus and the grid is relatively small, the speed raise and lower pulses are fixed width pulses whose width was adjusted during commissioning to prevent hunting near the point of synchronization. Once the voltage and phase angle difference between the campus and the grid are within tolerances, the RTAC issues a CLOSE command to close the selected breaker via the SEL-351-7 relay on that breaker. The CLOSE command is supervised by a 25 element in the relay to ensure that campus is still in synch with the grid when the CLOSE command arrives.

Once the campus is resynchronized to the grid, the other utility feeder breakers can be closed via the HMI by again selecting the SYNC CLOSE control for the desired utility feeder breaker on the HMI screen.

Other RTAC System Functions

In addition to providing synchrophasor data to the RTAC for the synchronizing scheme, the automation controller provides a number of other key functions including:

- Communicate breaker position status to the gas turbine controls to indicate whether or not the generator was operating in parallel with the grid or in island mode.
- Communicate breaker position status to the relays on the incoming utility feeders to enable or block the voltage and frequency protection required by IEEE 1547.
- Provide an automatic load shedding scheme for the system when operating as an island to prevent overloading the CTG.
- Provide telemetry information on the utility supply and campus feeder circuits to the new CTG distributed control system ("DCS").
- Provide telemetry information on the utility supply feeders and new CTG to the local utility.

Parallel Versus Island Mode Status Indication to the Solar Gas Turbine Controls

Generator and prime mover control systems require status indication to indicate whether or not the systems are operating in parallel with a utility grid or other generating units or as an isolated system. From the prime mover perspective, the fuel control system operates differently when operating as a stand-alone unit versus operating in parallel with a utility grid or other generating units. From the generator perspective, the voltage regulator can be operated in voltage or field current control mode at all times but can only operate in power factor or VAR control mode when operating in parallel with the utility grid or other generating units.

When operating as a standalone unit, the prime mover fuel control system will attempt to operate the prime mover in isochronous mode, attempting to maintain a speed (frequency) set point. When operating in parallel with other units, the prime mover can be operated in isochronous mode, isochronous load sharing mode, or droop. When operated in parallel with a much larger machine or utility grid, the unit can be operated in droop or isochronous load control mode (where turbine real power output is controlled). For this system, the turbine is operated in isochronous mode when operating away from the utility and in isochronous load control mode when operating in parallel with the utility.

When operating as a standalone unit, the generator voltage regulator will attempt to operate in voltage control mode to maintain the generator terminal voltage to its set point. When operating in parallel with other units, the generator can be operated in voltage mode, var or power factor mode, or var sharing mode. When operating with a much larger machine or a utility grid, the generator can be operated in voltage mode or var or power factor mode. If the control system attempts to operate the generator in power factor or var control mode when the generator is operating in stand-alone mode, the voltage regulator will likely be driven to the maximum or minimum excitation limiter settings, potentially resulting in unacceptable generator terminal voltage and/or tripping the unit off line.

For this system, there are a number of breaker position statuses that need to be considered to determine if the CTG is tied to the utility. The RTAC is an ideal platform to collect the data necessary to determine if the turbine is tied to the local utility grid. The following logic was programmed into the RTAC to provide indication to the CTG of its grid connection status.

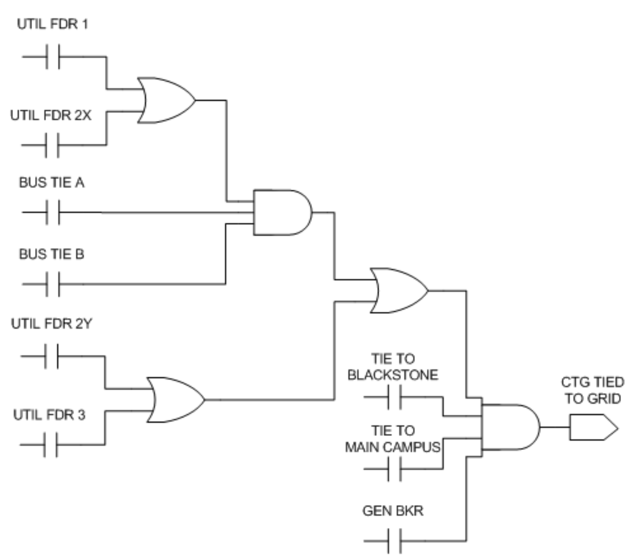

Figure 3
CTG "Tied to the Grid" logic

Utility Interconnection Requirements

IEEE Standard 1547 and the local utility have established requirements for voltage and frequency excursion for distributed generation. When the CTG is connected to the grid, the protection scheme from the distributed resource must include voltage and frequency elements with the set points listed in following tables.
The CTG is larger than 30kW so IEEE 1547 requires two under frequency elements, one of which the frequency set point and time delay are not defined by the standard. In the absence of a specific set point from the standard or the local utility, NERC standard PRC-024-1 [4] was used as a guideline. Specifically, the "Off Nominal Frequency Capability Curve" in Attachment 1 of the PRC-024-1 standard for the Eastern Interconnect formed the basis for the settings used in this application.

IEEE Std 1547-2003 Table 1
Interconnection System Response to Abnormal Voltages

Voltage Range (% of base voltage)	Clearing Time (seconds)
V < 50	0.16
50 ≤ V < 88	2.00
110 < V < 120	1.00
V ≥ 120	0.16

IEEE Std 1547-2003 Table 2
Interconnection System Response to Abnormal Frequencies

DR Size	Frequency Range (Hz)	Clearing Time (seconds)
≤30kW	> 60.5	0.16
	< 59.3	0.16
> 30kW	> 60.5	0.16
	< (59.8 – 57.0) adjustable set point	Adjustable 0.16 to 300
	< 57.0	0.16

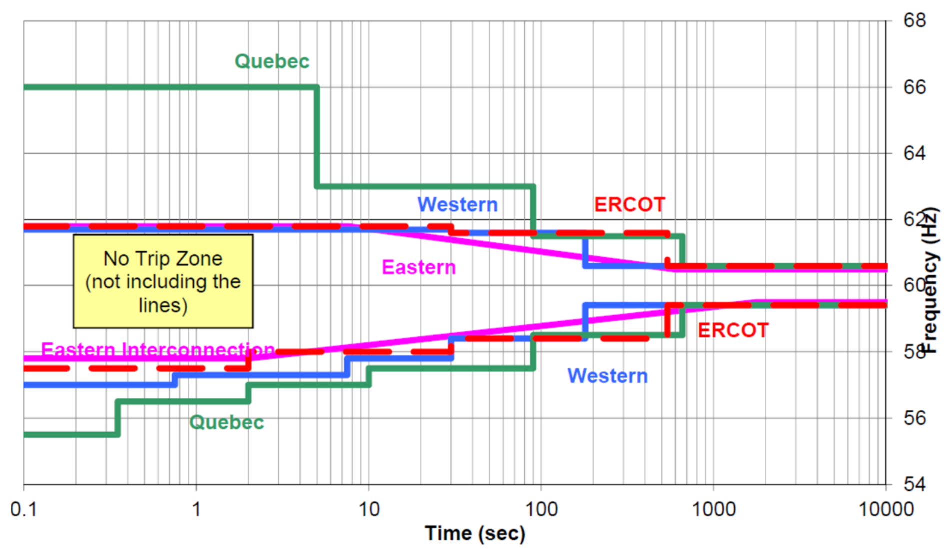

Figure 4
NERC PRC-024-1 Off Nominal Frequency Capability Curve

In addition to the under voltage and under frequency tripping set points from IEEE Standard 1547, utility Interconnection Requirements, and NERC PRC, frequency rate of change elements in the utility feeder breaker relays were enabled to provide fast tripping of the utility breakers based on the overloaded turbine speed decay characteristics provided by CTG manufacturer to increase the likelihood that the campus would island prior to the CTG tripping.

When the campus is connected to the local utility but the turbine is not online, implementation of these relay settings could result in nuisance tripping operations and unnecessary outages to the campus. To prevent this from occurring, the RTAC was used to provide signals to the SEL-351-7 relays on the four incoming utility breakers to block the operation of the voltage and frequency elements unless the CTG was tied to the grid. As shown in Figure 5, the logic is slightly different for the relays on Bus A since the presence of the tie breakers between the A and B buses has to be taken into account.

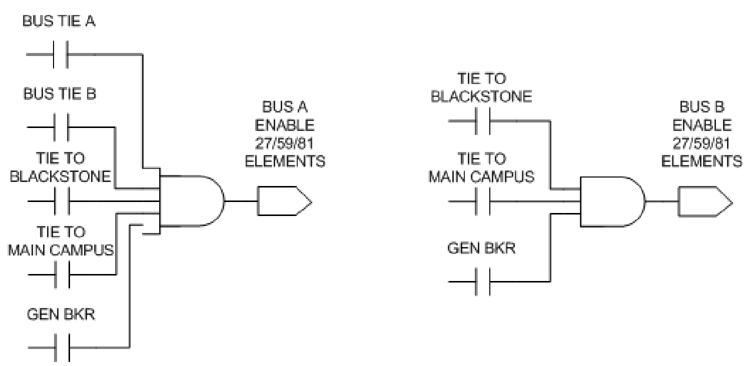

Figure 5
Voltage and Frequency Element Enabling Logic

Automatic Load Shedding

For the majority of the time, the CTG has sufficient capacity to supply 100% of the campus loads. However, since the CTG was sized to meet campus thermal loads, there are certain periods of the year when the campus electrical loads exceed the capacity of the turbine. Per information provided by the CTG manufacturer, the gas turbine can be loaded to 105% of its rated capacity for 20 seconds before the unit will trip due to over temperature. In addition, above 105% load, the turbine fuel control will limit the fuel to the turbine such that the turbine speed will decay at the rate of 20% per second per multiples of load above 105% load. The CTG manufacturer also recommends loading the machine to no more than 85% of capacity in island mode. As such, an automatic load shedding system was implemented in the control system to maintain the load on the turbine within the manufacturer's specifications.

In order to implement the load shedding scheme, the RTAC collects load data from the incoming utility feeders and the outgoing campus distribution feeders and the instantaneous capacity of the turbine. As was noted above, the relays on the four utility feeder breakers were upgraded to new SEL-351-7 relays. The campus feeder breakers are equipped with older generation SEL-351 relays which have the capability to provide real time feeder loading and can accept binary control signals via RS-232 and RS-485 ports on the relays. The gas turbine control system provides an analog signal to the SEL-700G relay on the generator breaker to indicate the instantaneous real power capability of the turbine based on ambient conditions. The instantaneous real power supplied to the campus is calculated and then compared against the instantaneous capacity of the turbine to determine if load shedding is required.

The following logic was coded into the RTAC to implement loading shedding if enabled. The load shedding logic allows up to 5 feeder breakers to be tripped in sequence if load shedding is required. The order of the feeders to be shed is pre-selected and is not based on individual feeder loading. The RTAC continuously monitors campus load relative to turbine capacity even when the system is operating in parallel with the grid. In the event of a loss of utility power, the protection scheme will trip the utility feeder breakers. If the campus load exceeds 85% of the turbine capacity, the system will instantly start to trip campus feeder breakers based on the pre-selected tripping order until the load is reduced to 85% of the turbine capacity. From that point, the RTAC will continue to monitor the system loads to maintain the turbine loading but will allow the turbine to operate at up to 95% of its capacity for two hours. If the load exceeds 95% of the turbine capacity or if the load is between 85% and 95% of the capacity for more than two hours, the load shedding scheme will trip additional breakers to reduce the load to less than 85%. The scheme does not provide for automatic restoration of the campus feeder breakers. Per the direction of the Harvard, the system was designed for manual restoration of campus feeder breakers.

Telemetry Data

Another requirement for the RTAC system is to provide telemetry data to both the Blackstone plant DCS and the utility's SCADA system. In order to provide increased data security, two additional RTAC's were installed with stand-alone data security appliances to buffer telemetry data between the control system RTAC and the plant DCS and utility SCADA systems. In addition, a serial encryption device was installed on the link to the utility SCADA system.

Control System Redundancy and Reliability

The control system is based on a single RTAC with redundant communication paths. Power for the controls is supplied from the station batteries at the Main Campus Station and at Blackstone. All the relays are equipped with redundant communication channels. The new SEL-351-7 relays on the incoming lines and the new relays at Blackstone have dual Ethernet ports with automatic failover enabled. The older style SEL-351's communicate via a RS-485 and a RS-232 port on the relays through redundant port servers.

The RTAC is configured to send a "heartbeat pulse" to each of the relays on the incoming line breakers and the breakers at Blackstone. In the event of a failure of the RTAC or the loss of communication to the relays and thus the loss of the heartbeat pulse, an alarm will be communicated to the plant DCS and the relays will default to the following conditions.

1. For each of the SEL-351-7 relays on the incoming utility feeders, the voltage and frequency elements will be ENABLED.
2. For the CTG tied to the grid logic in the SEL-700G relay at Blackstone Bus C, the "CTG Tied to the Grid" signal to the Solar gas turbine controls will indicate "CTG Tied to the Grid" if the 52G breaker is closed.

Testing and Commissioning

Commissioning and validation of the remote synchronizing scheme was deemed to have sufficiently low risk to be performed on the distribution system during normal working hours but was performed in stages to further minimize the risk of a power interruption. The first test was performed with all of the campus load transferred to the "A" bus and the synchronizing test performed on the unloaded "B" bus. The generator was started and synchronized normally at Blackstone with the generator serving only plant auxiliary loads. The utility breaker supplying "B" bus was then opened and then the automatic synchronizing scheme initiated to prove that the RTAC could be control the generator to synchronize and reconnect Bus "B" to the utility. Finally, the entire campus was islanded to prove that RTAC could reconnect the islanded microgrid back to the local utility.

In order to avoid disruption to campus operations, the load shedding scheme was verified in a lab environment. The campus load and turbine capacity were simulated which enabled the load shedding scheme control functions to be verified.

Conclusions

The use of a RTAC-based control system proved to be an effective means to remotely re-synchronize an islanded microgrid to the utility grid, to provide automatic load shedding to maintain turbine loading within its capacity in real time, and to send telemetry and operating data to multiple clients. The control scheme was specified with redundant communications but only a single controller which did raise concerns about overall system reliability. Since the RTAC continuously provides status indication to the CTG and the utility feeder breaker relays, provisions were built in the control system to detect a loss of communication and place the system in a stable and safe operating condition. In addition, a spare, hot swappable RTAC was supplied to permit restoration of normal control system operation quickly in the event of an RTAC failure.

BIBLIOGRAPHY

[1] Mass Save, "Guidebook for Submitting CHP Applications for an Energy Efficiency Incentive in Massachusetts", November 2010.

[2] IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems", 2003

[3] Eversource Energy, Massachusetts Technical Specifications for DG Interconnection, 2015

[4] NERC Standard PRC-024-1, "Generator Frequency and Voltage Protective Relay Settings", May 2013