# Distributed Generation Intertie With Advanced Recloser Control

John W. Gajda
*Progress Energy Carolinas*

Mark Lanier
*Schweitzer Engineering Laboratories, Inc.*

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Mark Lanier, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Progress Energy Carolinas installed an advanced recloser control in summer 2007 at the intertie to an independently owned and operated distributed generation facility. There are twelve 335 kW (419 kVA) generators operating at 480 V connected to the Progress Energy 23 kV distribution system through wye grounded-wye grounded transformers. The advanced recloser control was installed in conjunction with a solid dielectric, three-phase, individual pole recloser at the intertie location and at two upstream locations on a distribution feeder. It will provide all of the recommended protection for distribution-interconnected generation per IEEE Standard 1547-2003, IEEE Standard for Interconnecting Distributed Resources With Electric Power Systems. In the interest of avoiding the expense and complexity of a transfer trip scheme, added protection is desired to prevent islanding of the generators. In addition to several protective elements, such as frequency and voltage, the recloser control implements directional overcurrent protection, supervised by load encroachment as an added measure to detect faults and to protect against inadvertent islanding operation.**

**The upstream line reclosers and controls (of the same type as at the generating facility) have a very fast automatic reclosing open-interval time. These reclosers are configured to prevent reclosing when the utility system is out of phase with the generation.**

**A high-speed serial communications link between the generating plant control system and the recloser control will trip and keep the generators offline in the event of a distribution system fault. The generators must trip offline within 10 cycles to prevent the recloser from tripping. The intent is to leave the recloser at the generating plant tie closed so that after a successful upstream reclose operation, the generators can be resynchronized to the grid.**

**During normal operations, reactive power exchange is technically a concern for both the utility and the generator. The advanced recloser control can monitor the status of the generation facility's regulator control (power factor control mode versus voltage control mode). The unique nature of the protection employed prevents reactive power exchange outside of defined limits.**

## I. Introduction

While independent power producers (IPPs) have been operating on distribution systems for decades, there is clearly a current resurgence of new interconnection activity in this area. IEEE Standard 1547-2003, IEEE Standard for Interconnecting Distributed Resources (DR) With Electric Power Systems (EPS) [1], was created in response to a need for IPPs and utilities to agree on what utilities might require for safe and effective operation of generation in parallel with the utility distribution system.

This specific IPP approached Progress Energy Carolinas in 2005 with a request to interconnect to the utility distribution system and produce 4 MW of electricity for export. The local distribution feeder, Fort Barnwell, operates at 22.86 kV (phase-to-phase) nominal and is characterized by approximately 50 miles of three-phase trunk feeder. The feeder is split into two main protective zones, each protected by a three-phase recloser. See Fig. 1 for a topology of the feeder.

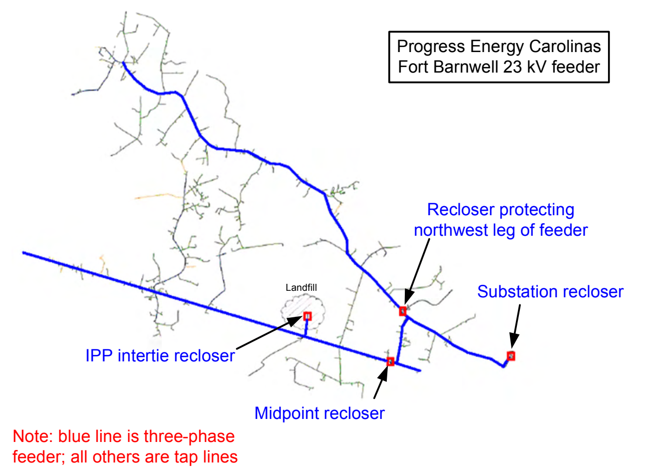


Fig. 1. Distribution feeder topology for Fort Barnwell feeder

IEEE 1547 addresses a number of issues, some related to normal operations (e.g., voltage regulation) and some related to abnormal operations (e.g., generation facility response to distribution system faults).

This paper is not intended to be a comprehensive review of IEEE 1547 or its substandards, so the reader is encouraged to become familiar with the standard in conjunction with the review of this paper. A primary intention within this paper is to show, through installation of an advanced recloser control and recloser at the generating facility intertie and at two other locations on the feeder, how the requirements of the following applicable sections of IEEE 1547 have been met:

- Section 4.1 General Requirements
  - 4.1.1 Voltage Regulation
  - 4.1.2 Integration With Area EPS Grounding
  - 4.1.3 Synchronization
  - 4.1.5 Inadvertent Energization of Area EPS
  - 4.1.6 Monitoring Provisions
  - 4.1.7 Isolation Device

- Section 4.2 Response to Area EPS Abnormal Conditions
  - 4.2.1 Area EPS Faults
  - 4.2.2 Area EPS Reclosing Coordination
  - 4.2.3 Voltage
  - 4.2.4 Frequency
  - 4.2.5 Loss of Synchronism
  - 4.2.6 Reconnection to Area EPS
- Section 4.4 Islanding
  - 4.4.1 Unintentional Islanding
  - 4.4.2 Intentional Islanding

As part of a system impact study, short-circuit studies and load-flow studies provided the background data required to understand what type of protection would be effective, where it would be needed, and how devices would have to be set. It is critical that a networked short-circuit study be done, rather than a strictly radial short-circuit study, as is most often done for distribution systems. Short-circuit studies for this application must have results available for each case: fault flow contributions, voltage levels at designated buses, voltage and current phase angles, and sequence quantities. See Fig. 2 for a simple feeder schematic that aided in system modeling.

One primary concern of IEEE 1547 is the prevention of inadvertent or unintended islanding, a condition during which the IPP generation remains in operation, serving local utility distribution load even though the utility system has had a protective device open somewhere upstream of the generation. While a typical solution for this problem with larger IPPs has been implementation of a transfer trip scheme, such schemes involve significant complexity and expense (compared to the balance of other equipment required) that can seriously affect the startup economics of independent generating facilities. Implementation of a local protection scheme allowed the greater complexity and cost of a transfer trip scheme to be averted.

The local protection scheme chosen uses directional overcurrent relaying with the load-encroachment feature of the advanced recloser control at the intertie location. This scheme, in conjunction with the other voltage-based protective elements and the voltage regulation mode of the generator, allows local fault detection and protection to prevent unintended islanding.

When the advanced recloser control detects a utility system fault, it is desirable, if possible, that the generators' breakers trip, rather than the utility recloser. In the implementation described here, a high-speed communications link between the advanced recloser control and the generating facility sends a trip signal from the recloser control to the generator trip circuits. The trip signal is maintained to block the restart of the generators until three minutes after the voltage and frequency conditions return to normal on the utility side of the recloser. Each of the advanced recloser controls on the distribution feeder is equipped with DNP3 SCADA communication to the utility's centralized grid management control center. This allows the utility to properly manage the distribution feeder and have real-time information on the status of feeder devices and the generating facility. If required for switching and tagging reasons, the utility can remotely control the generating facility's generators (via the recloser control and high-speed communications link) or the recloser itself.

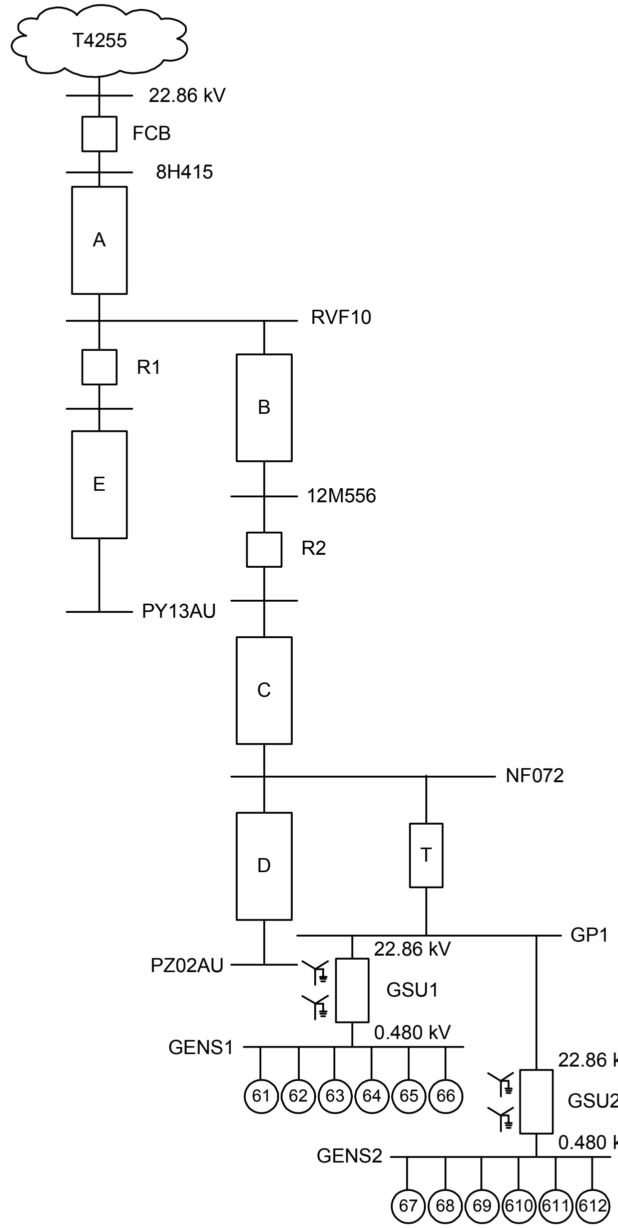


Fig. 2. Simple feeder schematic used for system modeling

Enhanced monitoring at the recloser control allows utility verification of the mode of generator voltage control. Since IEEE 1547 requires independent generators to not actively regulate voltage at the utility intertie, generating facilities generally will be required to run in a power factor control mode rather than in a voltage control mode. Review of load profile data (including reactive power flow and calculated power factor) and/or remote, real-time monitoring through a separate communications link to a third communications port allow the utility to view whether or not the generating facility is running in constant power factor mode. Little to no reactive power flow in either direction indicates power factor mode.

Varying reactive power flow throughout the course of a day as the generator exciters attempt to regulate the changing utility system voltage indicates voltage control mode.

Enhanced protection at the recloser control allows an enforcement mechanism related to reactive power exchange. The anti-islanding protection method, utilizing the advanced recloser control's load-encroachment feature, effectively sets a maximum bandwidth of power factor (± around unity) between which the generating facility can operate. The utility may designate the operating power factor for the generating facility (based on load-flow and voltage studies). Operation outside of this bandwidth may result in a trip signal. Rather than relying on metering data gathered on a monthly basis to enforce the reactive power exchange agreement, enforcement is automatic and instant.

## II. Isolation Requirements of IEEE 1547

IEEE 1547 Section 4.1.7 specifies the possible utility requirement of an isolation device. Progress Energy Carolinas' switching and tagging rules require that there be a method to isolate IPPs from the system. The isolation device must be visible-break and be readily accessible and lockable.

While this device could be a manually operated switch, Progress Energy Carolinas chose a recloser and advanced recloser control as both the isolating and interconnection device because of the many advantages the recloser and control offered in totality, including remote monitoring and control capabilities.

Every new recloser and advanced recloser control installation in Progress Energy Carolinas, regardless of location or application, includes a nine-blade manual bypass arrangement. The normal equipment as delivered from the manufacturer consists of, for each phase, a source switch, load switch, and bypass switch.

On normal line recloser installations, the bypass switches allow continuity of service when a recloser and control are taken out of service. The source and load switches allow isolation of the recloser from system voltage.

At the intertie location, the bypass switches should never be closed, since this would allow interconnection of the generating facility to the utility system without the recloser in service; the recloser is the interconnection protection device and can never be out of service when the generating facility is producing power. In order to avoid unintended use, installation crews were directed to modify the bypass arrangement before installation. The bypass switches were removed so that only the source and load switches remained. These switches remain as a useful, visible open point when needed for de-energized work. Fig. 3 shows the source/load/bypass switch arrangement used at these installations. Fig. 4 shows an intertie recloser installation at the IPP site.

Fig. 3. Bypass arrangement used on another recloser installation of the same type as mentioned in this paper

Fig. 4. Intertie recloser installation at IPP site. On the right side of the pole are three 1 kVA PTs monitoring utility voltage. To the left of the pole, the next structure is the IPP point of demarcation and the connection point to underground cables leading to the IPP.

## III. Voltage-Based Protection Requirements of IEEE 1547

The most essential protection requirements of IEEE 1547 are undervoltage (27), overvoltage (59), underfrequency (81U), and overfrequency (81O). These protective elements address Sections 4.2.3 and 4.2.4 of IEEE 1547 (voltage and frequency protection) and indirectly address Sections 4.2.1 (response to system faults) and 4.4.1 (unintentional islanding). Since most system faults on the local distribution feeder will result in voltage excursions outside of protection set points, islanding that results from an upstream utility protective device opening results in further voltage and frequency excursion. These protective elements therefore trip the generating facility offline and allow quick disconnection from the distribution system.

Very small IPPs (those with capacity that can never approach that of the local distribution protective zone) often require no other interconnection protection beyond these voltage-based protection schemes for a successful implementation under IEEE 1547.

To accomplish the required protection at this site, voltages had to be monitored on the utility side of the recloser. The advanced recloser control is capable of receiving six voltage inputs. Three inputs are from the utility side of the recloser, sourced from three 1 kVA distribution transformers, while the other three inputs are from the generating facility's side of the recloser, sourced from three low-energy capacitive voltage sensors, located in the bushings of the solid dielectric recloser. See Fig. 4 for a photo of the recloser and utility-side PTs.

The utility-side voltages are used for the 27, 59, 81U, and 81O protection elements. IEEE 1547 has default voltage and frequency set points for very small generators (≤ 30 kW); these set points are suggested as defaults for generators greater than 30 kW and were used as a starting point in this implementation, with some adjustments based on short-circuit studies.

The advanced recloser control has a number of voltage and frequency elements (and associated time delays) to accomplish two 27 elements, two 59 elements, one 81U element, and one 81O element. See Fig. 5 for a photo of the advanced recloser control at the interconnection site.

Fig. 5. Advanced recloser control at the interconnection site

To help address IEEE 1547 Section 4.1.5 (inadvertent energization of area EPS), the advanced recloser control utilizes the voltage signals from the recloser's utility- and generator-side voltages to implement live-line/dead-bus permissive closing logic. This not only prevents closing on a "dead" utility system but also avoids closing with a "live" generating facility, as the recloser is not a synchronizing device. (While synchronism check is a function available in the advanced recloser control, it is not utilized in this application.)

## IV. Additional IEEE 1547 Protection Requirements for Fault Detection and Anti-Islanding: Transfer trip Scheme and Associated Cost

For larger IPPs (those with capacity that approaches that of the local distribution protective zone), IEEE 1547 Sections 4.2.1 (response to system faults) and 4.4.1 (unintentional islanding) remain unfulfilled with strictly voltage-based relaying. Unintentional islanding, a possibility when a generation-to-load match could occur, is a condition during which the IPP generation remains in operation serving local utility distribution load, even though the utility system has had a protective device open somewhere upstream of the generation.

A common solution for this problem with larger IPPs has been implementation of a transfer trip scheme, a communications-based form of protection. In such a scheme, upstream utility protection, such as feeder circuit breaker relaying, sends a trip signal to an interrupting device at the generator location via a remote communications link. Such a link typically can be monitored. When the communications link goes down, thereby compromising protection, SCADA alarms can alert utility operations. The utility can then take steps to take the generation offline until communications circuit repairs are completed. Alternatively, local communications circuit monitoring at the IPP can automatically trip the IPP offline.

The advantage of such a scheme is that the protection becomes no more complex than local voltage-based protection and the transfer trip scheme.

Such schemes, however, can involve significant complexity and expense (compared to the balance of other equipment required) that can seriously affect the startup economics of independent generating facilities. Multiple protective zones upstream of the IPP increase the number of sites potentially involved in a transfer trip scheme; hence, they come with a corresponding increase in cost and complexity.

Typical communications technologies for transfer trip are:

- Local telephone company leased line
- Spread-spectrum radio
- Fiber-optic link

In all cases, installation of communications infrastructure (either by the utility or by a telecommunications entity, who then charges monthly service fees for use of the facilities) can be substantial. Keep in mind, too, that any technology used for a transfer trip scheme must be able to transmit signals in approximately less than 2 cycles (≤ 0.033 seconds), else it will be useless for protection purposes.

It is not the purpose of this paper to provide detailed economic analysis of this point, since it will be highly variable based on specific cases; hence no numeric cost values are referenced. Generation facilities geographically close to existing utility communications infrastructure will incur substantially lesser costs for communications, while those farther away will see significantly greater costs. Also, existing internal infrastructure across utility systems varies widely within and across utilities.

In this particular project, the capital cost of telecommunications infrastructure would have been approximately 30 percent of the project investment. The other 70 percent included the three recloser installations, metering, testing, and commissioning.

One purpose of this paper is to highlight the point that any scheme that could assure protection and compliance with IEEE 1547 but avoid remote communications would be economically most desirable; removal of a remote communications scheme with associated infrastructure is also desirable.

## V. Additional IEEE 1547 Protection Requirements for Fault Detection and Anti-Islanding: Current-Based Protection With Directional Overcurrent and Load-Encroachment Settings

Certain options for local protection of utility fault detection and unintentional islanding at the generating facility to the utility intertie, such as line distance relaying, directional overcurrent relaying, overcurrent with voltage restraint, or combinations thereof, have all traditionally carried their own particular implementation difficulties for use on the distribution system.

Line distance relaying, well understood and widely used for transmission line relaying, is not typically applied on distribution systems due to the preponderance of tap lines, other reclosing devices, etc.

Directional overcurrent relaying (67) for IPPs is typically problematic due to the steep descent rates of generator decrement curves. These decrement curves typically show that a generator cannot sustain the ability to feed a utility fault at levels in excess of its full load current rating. The set point of such a relay would have to be below that of the generator's full load capacity, which makes this method typically unworkable.

As mentioned in the introduction, the local protection scheme chosen uses directional overcurrent relaying with the application of a load-encroachment feature of the advanced recloser control at the intertie location.

The directional overcurrent pickup was set at the minimum pickup level allowed by the recloser control, 0.05 A secondary. The recloser CTs were tapped at a 500:1 ratio; thus the directional overcurrent will pick up for current greater than 25 A primary. The directional overcurrent is set to detect current flow towards the utility to look for faults on the feeder. Based on the physical mounting of the recloser and CT, polarity forward direction is looking into the generators, and reverse direction is looking toward the utility (see Fig. 6). Therefore, normal current flow when the generators are online and operating will be above the reverse directional overcurrent pickup level. Approximately three running generators will produce at or more than 25 A primary. The negative-sequence directional element and load encroachment prevent undesired trips for normal operation.

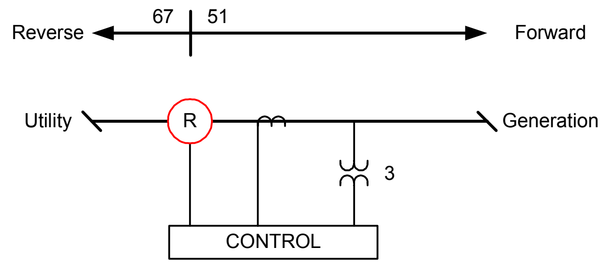


Fig. 6. Diagram of directional overcurrent protection (67) and transformer fuse backup protection (51)

The directional element in the recloser control utilizes negative-sequence voltage polarization for unbalanced faults. The directional element must have a minimum of 0.05 A secondary (25 A primary) of negative-sequence current (3I2) to operate. Therefore, with normal, balanced load flow out of the generators (expected operation), the directional element is not asserted. When an unbalanced fault occurs (phase-to-phase or phase-to-ground), the directional element will assert for a reverse fault (toward the utility) and allow a trip via the directional overcurrent element. Note that the generators may therefore trip for a fault on the feeder to which they are connected (desired operation) or possibly for a fault on an adjacent feeder out of the same substation (not desired). The undesired trips for faults on adjacent feeders are deemed acceptable to the distributed generator. The fact that they do not have to pay monthly fees to maintain a transfer trip scheme offsets the nuisance of infrequent undesired trips. In this location, the distributed generation (DG) site is a manned operation, and the generators can quickly be restarted after such a trip.

For balanced three-phase faults, the directional element is polarized by a positive-sequence directional element. This element would allow a trip for normal load flow, but this element is supervised by load encroachment. Load encroachment provides a user-settable phase-angle window in which the positive-sequence directional element is blocked. When a fault occurs, the phase-angle relationship between voltage and current shifts such that the current lags the voltage by approximately the line impedance angle. This shift moves outside the load-encroachment region, and a trip is allowed. For this application, load encroachment applied in this manner provides the added benefit of tripping if the generators operate outside of their rated power factor operating range. This is discussed further in Section X.

Settings applied for load encroachment in this application were:

Positive forward load angle: 85 degrees

Negative forward load angle: 85 degrees

Positive reverse load angle: 155 degrees

Negative reverse load angle: 205 degrees

The reverse load angles are ± 25 degrees of 180 degrees. This allows the generators to operate at 0.91 power factor lead/lag without tripping. Operation beyond 0.91 power factor with greater than 25 A primary will result in a trip. The forward load angles were set wide open to prevent the 50 element from tripping for any forward current flow.

In addition to the directional overcurrents (67), time-delay overcurrents (51) were applied to provide backup protection to the transformer high-side fuses and protect the conductors between the recloser and the fuses. The time-delay overcurrents were set above rated output and slower than the decay of the fault current contribution of the generators; thus, they will not trip for utility system faults (reverse faults).

## VI. IEEE 1547 Section 4.2.2 (Area EPS Reclosing Coordination): Upstream Reclosers Set to Prevent Out-of-Phase Reclosing

IEEE 1547 Section 4.2.2 (area EPS reclosing coordination) requires that utility device reclosing be coordinated with IPP interconnection protection. This essentially means that there should be no expected out-of-phase reclosing events.

When an upstream utility protective device opens, any interconnected IPP in question must, through effective fault detection, trip offline in less than two seconds (IEEE 1547 Section 4.4.1). If this utility protective device is set for initial reclosing in less time, utility voltage may be applied to the generator(s) again before the generator(s) have separated from the system. Since there is nothing to keep the generation and utility synchronized during the open-interval time of the upstream utility protective device, this amounts to an unsynchronized, paralleling event.

The primary risk associated with out-of-phase reclosing is damage to the IPP's generator shaft(s) from excessive applied torque. While in the past, this has been viewed as primarily a concern of the IPPs, this IEEE section requires both parties to consider this an undesired operation.

Coordination of the interconnection protection delays and utility reclosing open-interval times can help minimize the chances for out-of-phase reclosing events. Voltage-supervised reclosing nearly assures that this type of event cannot occur.

In voltage-supervised reclosing, a voltage signal from the load side (rather than the source side) of a reclosing device (breaker, recloser) can be used as a blocking signal for closing. Therefore, when a device has tripped, has gone through its recloser open-interval time, and is ready to reclose, the presence of voltage on the load side (generally only possible if the IPP is still running and applying potential to the local utility protective zone) can block the closing action.

Progress Energy Carolinas uses a very fast initial reclosing open-interval time on its feeder circuit breakers and electronic reclosers—typically about 0.25 seconds. In the IPP application studied here, there were two utility reclosing devices between the utility substation and the IPP facility—a three-phase recloser at the substation and a three-phase recloser about halfway down the feeder.

Voltage-supervised reclosing was very straightforward to apply at each of these installations. Load-side voltage signals available on each recloser from three low-energy capacitive voltage sensors (located in the bushings of the solid dielectric recloser), along with use of programmed logic in the advanced recloser controls, allowed voltage-supervised reclosing on a per-phase basis (recloser is three-phase with independently operating poles).

## VII. Communications: High-Speed Link Between Advanced Recloser Control and Generator Breaker Controls

There were many operational advantages to establishing low-cost communications links to the utility's centralized SCADA system and to the IPP facility. While two of the three serial ports on the advanced recloser control were utilized for low-cost remote utility communications (described in Section VIII), one of the ports was allocated to a special high-speed communications protocol that linked eight status points between the advanced recloser control and a remote I/O module in the IPP facility's control room.

Utilizing fiber-optic cable through a several hundred foot conduit connecting the advanced recloser control and a remote I/O device located in the IPP control room with serial/fiber-optic converters on either end, the high-speed link accomplishes status point change communications in less than 1 cycle. This is a key point, since the shared bits across the link can be considered "contacts and coils" or "status" points that can be used generally without regard or worry about time delay, due to the high-speed nature of the connection. Without this high speed, some of these shared points would lose their operational value. The link is also monitored, and, if communication is lost for 10 seconds, the recloser trips.

The high-speed communications link, in conjunction with logic equations programmed into the advanced recloser control, allows several capabilities listed here.

### *A. Signals Transmitted From Advanced Recloser Control to IPP Control System Remote I/O Module*

#### *1) Transmission of "Trip" and "Block Close" Signals From Advanced Recloser Control to IPP Control System*

These signals, trip and block close, allowed the possibility of implementing a local transfer trip scheme, by which trip signals generated by the advanced recloser control could be passed on to the IPP's control system, thereby causing generator breakers to trip. This action removes the need for the recloser itself to trip; it can remain as a backup trip device if it does not get verification that all generators have tripped in less than the utility's upstream reclosing open interval (e.g., in this case, less than 15 cycles; see first "receive" bit in Section VII.B).

The advantages of this scheme are that the IPP retains an energized generator bus even when its generators have to be tripped (as opposed to the whole facility tripped off) and that the recloser does not undergo operation except as a backup device, which positively impacts recloser service life and maintenance.

Such a scheme can only be implemented if the IPP facility is capable of receiving the trip signal, tripping all generator breakers, and sending the verification signal back to the advanced recloser control in less than the utility's upstream reclosing open interval (e.g., in this case, less than 15 cycles).

The IPP at this site used a station master programmable logic controller (PLC) along with generator PLCs and multiple communications links, resulting in a total signal propagation time (receipt, generator tripping, return signal to recloser control) of approximately 100 cycles (1.7 seconds).

This was much slower than the required 15 cycles, so logic was modified after this initial testing such that the advanced recloser control tripped the recloser directly rather than transferring the trip signal to the IPP. However, the final implementation included sending this signal, allowing a backup trip method (if the recloser fails to trip), and preventing the generator breakers from closing (via the block close signal) when the recloser is open.

*2) Verification of Loss of at Least One-Phase Voltage on Utility System*

The IPP control room operator can receive positive verification that, while the recloser is open, the utility system has a loss of voltage on one or more phases, which likely means there is an upstream protective device locked out.

*3) "Close Block" Active on Advanced Recloser Control*

The former hot-line tag feature of the advanced recloser control was relabeled on the control panel and used as a close block function, to be used when the utility opens the recloser and wants it to stay locked open until further notice. This signal notifies the IPP control room operator that the advanced recloser control is in close block status.

*4) Verification of Recloser Open/Close Status for All Poles*

The IPP control room operator can receive positive verification that all recloser poles are open or all recloser poles are closed.

*5) Status of Recloser When Open: Locked Out or Just Held Open Until Utility System Is Restored*

Certain events cause a complete lockout, such as an emergency trip sent from the IPP control room (see second "receive" bit in Section VII.B). Logic in the advanced recloser control prevents the recloser from closing automatically when in this state; utility personnel must first press "Target Reset" on the recloser control to reset the lockout state.

The IPP control room has notification through this bit that the recloser is in this locked-out state that cannot be changed without manual on-site intervention by the utility.

*6) Warning Signal That Recloser Reconnect Timer Is Preparing to Close*

When abnormalities (faults, undervoltage conditions, etc.) on the utility system result in a recloser trip, a three-minute reconnect timer starts after the advanced recloser control has no voltage or frequency elements picked up (i.e., normal voltage and frequency). When this timer is running, the IPP control room is alerted that the recloser is preparing to close and re-energize the generating facility generator bus.

### *B. Signals Received by Advanced Recloser Control From IPP Control System Remote I/O Module*

*1) Verification That All Generator Breakers Are Open—Additional Protection Against Unsynchronized Closing*

The IPP control system supplies a bit from their master PLC that is only asserted when all twelve generator breakers are open. This bit is then used in logic in the advanced recloser control to prevent closing of the recloser unless all generators are offline.

*2) Emergency Recloser Trip Signal From IPP Control Room*

While the recloser and advanced recloser control are owned by the utility, they directly serve the IPP step-up transformers and all 480 V facilities beyond. If IPP personnel have a problem in their 480 V facilities that does not cause the primary fuses on the step-up transformers to blow, it is convenient for IPP personnel to have the ability to trip the recloser. This bit is mapped directly to trip logic in the advanced recloser control, thereby allowing IPP personnel this capability during emergencies.

## VIII. Utility SCADA Communication

As mentioned earlier, the recloser and advanced recloser control installation could have theoretically been a standalone installation with no external communication and still have accomplished the interconnection protection requirements, but there were clearly many operational advantages to establishing low-cost communications links to the utility's centralized SCADA system and to the IPP facility itself.

While the first of three available serial ports was used for the high-speed communications link described earlier, the second port was utilized for a utility DNP3 SCADA connection.

The utility operates a distribution control center (DCC), which is a centralized distribution system dispatch and grid management control center. Cost-effective communications to the generator site were desired to effectively manage this unique feeder from the DCC.

The utility identified a relatively cost-effective solution for remote SCADA communication. Rather than leased line or communication reliant on a local wireline telecommunications carrier (phone/cable), the utility chose a data modem that operates over a local cellular telephone carrier's system and back to the utility's SCADA system. (For security reasons, there are no further details provided about the telecommunications.)

The utility chose to use this remote SCADA connection not only at the interconnection recloser but also at the substation recloser and at the midpoint recloser.

The DCC's ability to monitor and control all three reclosers, from the substation to the IPP, allows effective remote management of the entire feeder for the benefit of both the utility's customers and the IPP itself. Reports from DCC dispatching and grid management engineering personnel after the scheme entered service were very positive, as they were afforded monitoring and control capabilities commensurate

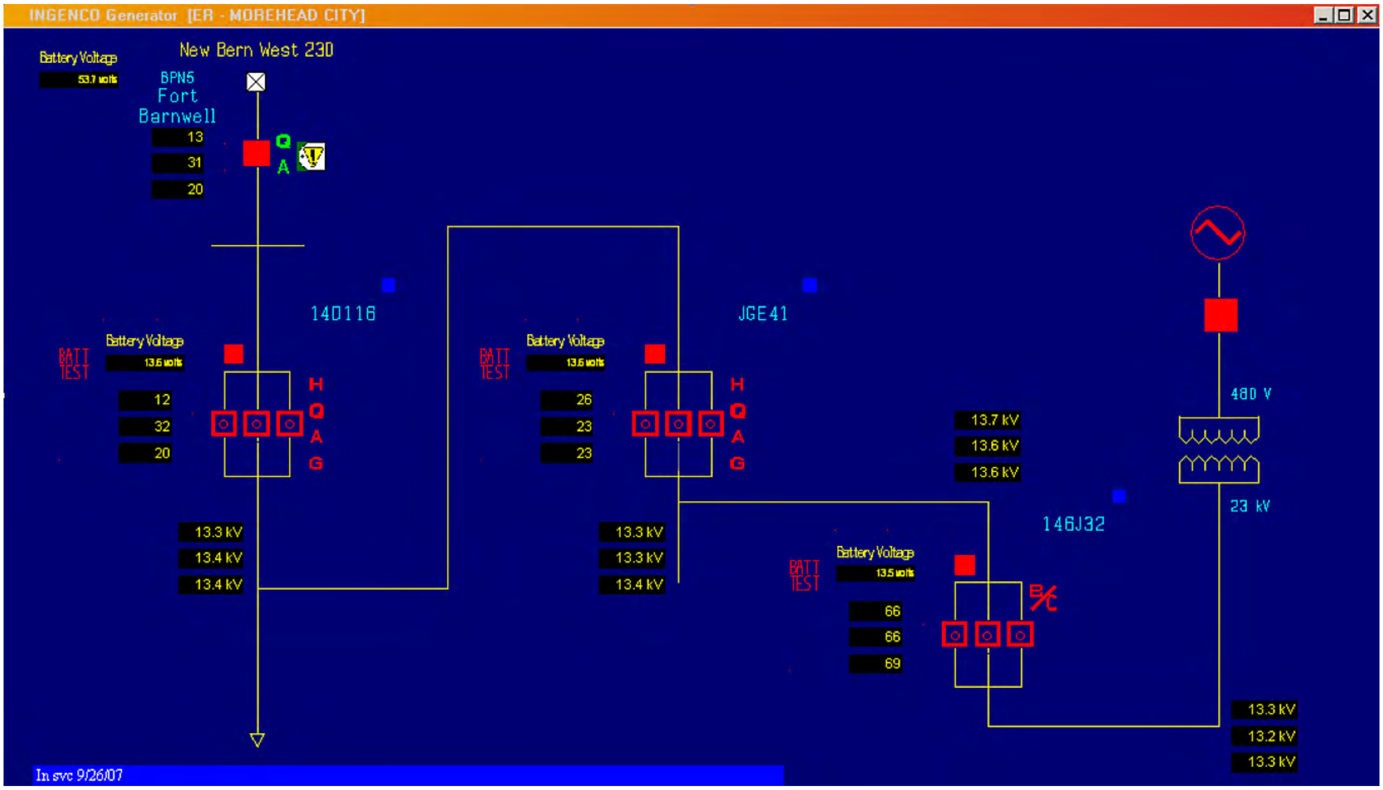


Fig. 7. SCADA operator display for Fort Barnwell feeder

with the expectations placed on them to understand and operate the system. See Fig. 7 for a screen image of the SCADA dispatcher display for the feeder.

DNP3 communication was enabled and points mapped such that the following was available for monitoring and control at each site:

- SCADA monitoring
  - Recloser open/close status per phase
  - Currents: A, B, C, and residual ground
  - Voltages: A, B, C on the load side (downstream) of the recloser, through use of the recloser's capacitive voltage sensors
  - Hot-line tag status (block close status for recloser at intertie)
  - Battery health
- SCADA control (for substation recloser and midpoint recloser)
  - Recloser open/close
  - Battery test initiate
  - Overcurrent element fast curves—enable/disable
  - Reclosing—enable/disable
  - Hot-line tag—enable/disable
  - Ground overcurrent element—enable/disable
- SCADA control (for interconnection recloser)
  - Recloser open/close
  - Battery test initiate
  - Close block—enable/disable

## IX. Utility Remote Diagnostic Communication

The third serial port on the advanced recloser control was enabled with a second data modem with connection to the utility via the local cellular telephone carrier. This communications circuit did not terminate at the utility SCADA system like the DNP3 connection mentioned before; rather, this circuit terminated inside the utility's internal network.

This unique connection allowed remote access to the advanced recloser control from engineering personnel responsible for the project, all of whom are located in utility company offices far from the IPP site. The software typically used for on-site advanced recloser control configuration, monitoring, testing, etc. (via a serial port connection from a laptop computer to the control) could now be used remotely, with data speeds comparable to local connections.

While remote programming of settings is possible, this is only done when a shutdown is coordinated with the IPP because of the critical nature of changing recloser settings. A dropped data circuit during remote transmission of settings could result in a disabled control until someone arrived at the scene to rectify the situation, possibly taking hours to days to correct.

The business case for this data connection might seem a little softer than that of the DNP3 SCADA connection. However, the ability to quickly assess problems or make small changes, a very normal activity in a new engineering system such as this, is of high value when the value of scarce engineering time (i.e., the avoidance of travel time for support engineers) is considered. To date, this connection has been of unquestioned high value to Progress Energy distribution engineering.

## X. Reactive Power Exchange—Monitoring and Enforcement/Control

IEEE 1547 Section 4.1.1 addresses voltage regulation: "The DR shall not actively regulate voltage at the PCC. The DR shall not cause the Area EPS service voltage at other Local EPSs to go outside the requirements of ANSI C84.1-1995, Range A."

For most exporting IPPs, this requires them to operate generator excitation equipment without regulating terminal voltage. Power factor control mode of operation, which is a control system mode for the excitation equipment, is a typical and straightforward method, which lends itself well to utility circuit modeling and study.

Load-flow studies help to determine how feeder voltage levels will be affected during feeder peak and minimum load, with IPP generation offline and online. At that time, the utility can determine an optimum power factor for the IPP's power factor control equipment. For this IPP, the utility requested that the IPP operate at unity power factor. Also important to note is that the interconnection agreement between the utility and IPP required that reactive power exchange not fall outside of ± 0.95.

Once in operation, however, the only method for the utility to monitor reactive power exchange is metering. While a four-quadrant meter provides sufficient data to monitor reactive power exchange (limited by the demand integration window), this metering is an "after-the-fact" monitoring task, requiring additional organizational steps within the utility to monitor the reactive power exchange on a monthly basis, making sure it does not go outside the window stated in the contractual agreement.

Organizationally in a utility, this task could very well "fall under the radar" of important things to do, although it is important for utility customer voltage quality.

The enhanced load profile monitoring and control capabilities presented a unique solution to these problems surrounding reactive power exchange. At this IPP site, some questions arose during the first few weeks of operation about the locally high voltages experienced at the IPP site when in operation, specifically during the early morning hours. Then one morning just after 2 a.m., the recloser tripped.

An investigation found that the recloser tripped as a result of the directional overcurrent/load-encroachment settings, which had been designed for fault detection and anti-islanding. Utility monitoring equipment had not picked up evidence of a distribution system fault, and review of the data from the advanced recloser control did not indicate evidence of a fault.

The utility proceeded with further investigation of the event by downloading the five-minute load profile data from the advanced recloser control. Reviewing data across multiple days, it was clearly observed that the IPP was not operating in a power factor control mode as required; rather, their reactive power exchange varied. Specifically, when the early morning hours approached (a time of minimum feeder load for the utility), voltage increased at the recloser, and IPP reactive power input continued to increase at a relative rate that tracked the voltage increase. This indicated that the generator excitation equipment was attempting to pull reactive power into the machines, in an effort to pull voltage down to some given set point. See Fig. 8 for a chart of load profile data from this time period. Note reactive power flow and voltage tracking together.

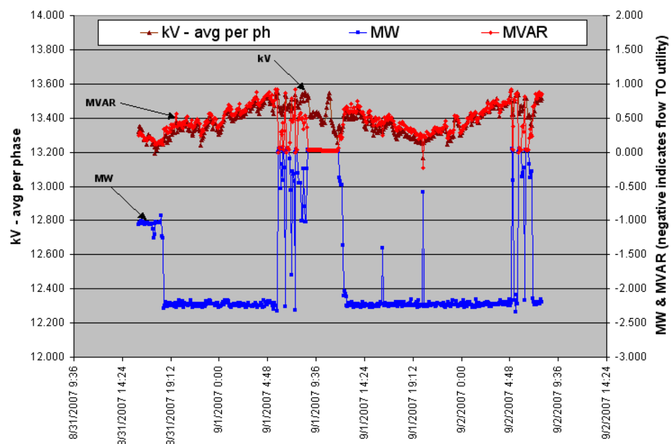


Fig. 8. Interconnection point voltage and power exchange several days after site commissioning

Specifically, the IPP facility's operating power factor at the time of the 2 a.m. trip event was approximately 0.94 leading. Since the directional overcurrent/load-encroachment settings rely on the IPP facility operating in a narrow power factor window (± 0.94 at the time), the offense that caused the trip was an operating power factor that dropped below 0.94 leading, as the IPP facility excitation equipment was still attempting to pull in more reactive power in an effort to reduce utility system voltage, albeit with no success.

When the IPP was contacted with this information, a review of their plant control system showed that they had inadvertently turned off the power factor control signal for the generator excitation at time of facility commissioning.

Once the IPP activated power factor control, load profile data were again checked and, this time, clearly showed power factor control working properly, with a very small constant reactive power input while the facility was operating at full load. See Fig. 9 for a chart of load profile data after the control system mode was changed. Note reactive power and voltage no longer tracking together.

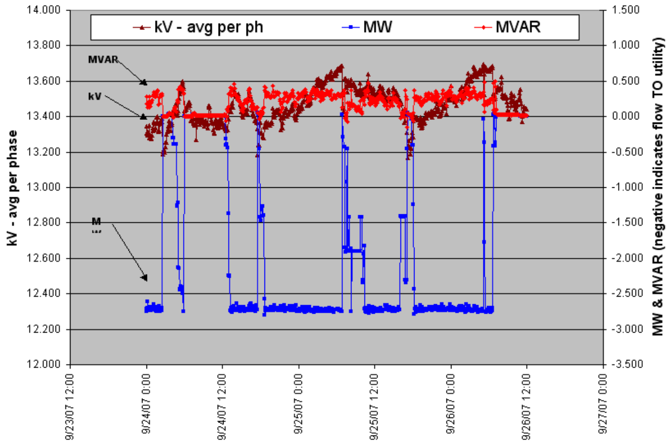


Fig. 9. Interconnection point voltage and power exchange several days after site commissioning

Therefore, the advanced recloser control served two additional purposes, both very important yet unintended—to monitor and enforce the reactive power exchange agreement between the utility and the IPP.

## XI. Post Installation Analysis

The distributed generation facility went online in late summer 2007. Since then, the IPP and utility have analyzed events, three of which are discussed here.

On September 18, 2007, a phase-to-phase fault occurred on one of the adjacent substation feeders, and the directional overcurrent element in the advanced recloser control tripped. The distributed generators were tripped through the high-speed communications circuit and were blocked from closing back in again for three minutes, as designed. Once the three-minute timer expired, the advanced recloser control automatically closed back (voltage and frequency were within limits since the fault was not actually on the DG feeder). Once the recloser was closed, the generators were brought back online. The event report data in Fig. 10 show that the 50P4 element was asserted at the beginning of the event, but the directionally controlled bit 50P4T did not time out and trip until the directional bit 32PR had been asserted for 10 cycles.

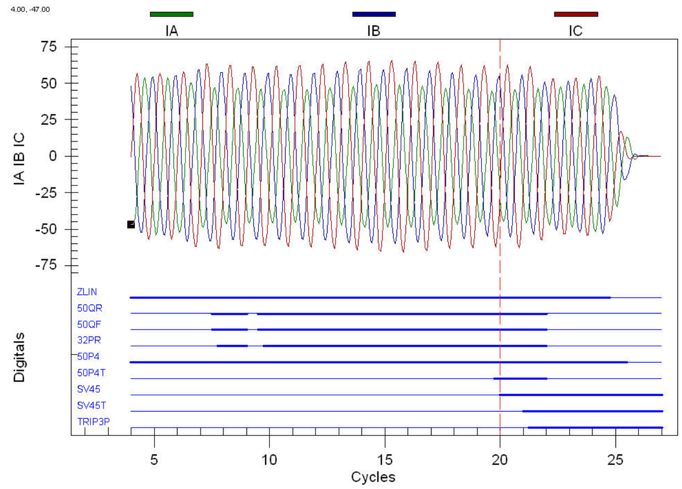


Fig. 10. Event report for trip due to adjacent feeder fault, September 18, 2007

Another phase-to-phase fault occurred on December 30, 2007, but for this fault, the recloser did not trip, and the DG stayed online as desired. Another device elsewhere on the system cleared the fault in approximately 3 cycles; thus, the directional overcurrent and undervoltage elements did not have time to trip in the advanced recloser control. As shown in Fig. 11, the directional overcurrent bit 32GR only asserted for approximately 1 cycle. The emphasis of including this event is to show that the undesired trip on September 18 does not occur every time there is a remote fault on an adjacent feeder. An undesired trip will only occur if the fault is cleared in slower than 10 cycles. Most fuses or a fast curve on a recloser will trip faster than 10 cycles.

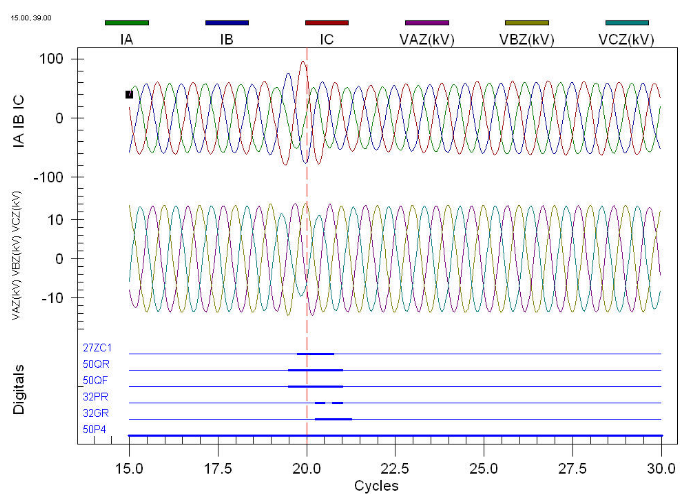


Fig. 11. Event report for phase-to-phase fault with proper operation, December 30, 2007

One final event of interest also occurred on December 30, 2007. The original protection design anticipated that the generators were solidly grounded, and that they would contribute zero-sequence current (ground-fault current) to any utility fault. At some time after installation, the distributed generator told the utility that the generators were in fact *ungrounded*. The utility considered implementing a zero-sequence voltage element (59N) to detect phase-to-ground faults on the utility system, since the ungrounded generators would not contribute ground-fault current. The advanced recloser control has the capability to detect 3V0, so this would have been an easy solution.

Prior to implementing the 59N protection, a phase-to-ground fault occurred on the utility feeder (see Fig. 12). The event report retrieved from the recloser control shows that the generators did indeed contribute ground-fault current, meaning that they must actually be grounded, intentionally or not. For this event, the advanced recloser control properly tripped for a rise in voltage on the two unfaulted phases. Note that the faulted phase was timing to trip on undervoltage, but the undervoltage delay was set slightly longer than the overvoltage delay.

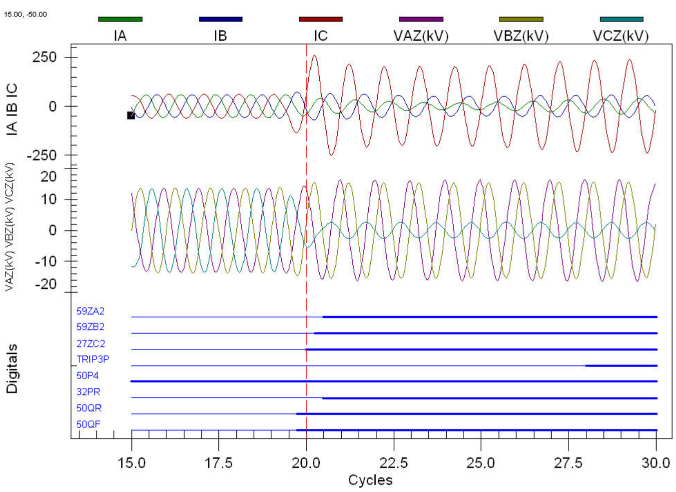


Fig. 12. Event report for phase-to-ground fault, December 30, 2007

## XII. Conclusions

Distributed generation is increasing in popularity in many areas today. For this particular IPP site, an alternative was sought to the direct transfer trip equipment and the associated annual costs. Each IPP site must be evaluated by the utility to determine if local protection is suitable or if the added cost and complexity of direct transfer tripping is required. Some of the advantages of the advanced recloser control at this particular site included:

- Standard protection as recommended by IEEE 1547.
- Backup protection with directional overcurrents and load encroachment.
- SCADA access for remote command and control, implemented with DNP3 protocol.
- Remote engineering access for data collection, such as load profile and event reports.
- Monitoring and enforcement of reactive power exchange.

The project is considered a very successful implementation and will be considered for future IPP sites by Progress Energy.

## XIII. Acknowledgments

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## XIV. Reference

[1] *IEEE Standard for Interconnecting Distributed Resources With Electric Power Systems,* IEEE Standard 1547-2003, Jul. 2003.

## XV. Biographies

**John W. Gajda, P.E.,** received his BS in Electrical Engineering from the University of Arkansas in 1990 and his MS in Electrical Engineering from North Carolina State University in 1994. Upon graduating, he first worked for Conoco Oil Co. as a systems engineer and then for Siemens as a medium voltage motor control specification engineer. In 1994, John joined North Carolina Electric Membership Corporation, designing and leading small power plant retrofit and installation projects. From 1999 to 2000, he worked as consulting engineer for Electrical Engineering Consulting & Testing and then left to serve a short time at the North Carolina Utilities Commission. Since 2001, John has been at Progress Energy Carolinas, serving as the company's corporate engineering resource for engineering design and training related to distribution system protection and distribution-interconnected generation. He is a registered professional engineer in the States of North Carolina, South Carolina, and Florida.

**Mark Lanier, P.E.,** received a BS in Electrical Engineering in 1989 and an MBA in 2007 from the University of South Carolina. From 1989 to 2003, he designed coal- and gas-fired power plant electrical systems at Duke/Fluor Daniel, a subsidiary of Duke Energy. He left Duke Energy to join Schweitzer Engineering Laboratories, Inc. as a field application engineer. He is a registered professional engineer in the State of South Carolina.