Mitigation of Undesired Operation of Recloser Controls Due to Distribution Line Inrush

Larry Wright
Schweitzer Engineering Laboratories, Inc.

Lee Ayers
Mid-Carolina Electric Cooperative

This paper was presented at the 2015 IEEE Rural Electric Power Conference and can be accessed at: http://dx.doi.org/10.1109/REPC.2015.20.

This paper was previously presented at the 68th Annual Conference for Protective Relay Engineers and can be accessed at: http://dx.doi.org/10.1109/CPRE.2015.7102174.

For the complete history of this paper, refer to the next page.

Presented at the
IEEE Rural Electric Power Conference
Asheville, North Carolina
April 19–21, 2015

Previously presented at the
68th Annual Conference for Protective Relay Engineers, March 2015,
14th Annual Clemson University Power Systems Conference, March 2015,
and 41st Annual Western Protective Relay Conference, October 2014

Originally presented at the
68th Annual Georgia Tech Protective Relaying Conference, April 2014

Mitigation of Undesired Operation of Recloser Controls Due to Distribution Line Inrush

Larry Wright
Schweitzer Engineering Laboratories, Inc.
2401 Whitehall Park Drive, Suite 200
Charlotte, NC 28273, USA
larry_wright@selinc.com

Lee Ayers
Member, IEEE
Mid-Carolina Electric Cooperative
P.O. Box 669
Lexington, SC 29071, USA
lee@mcecoop.com

Abstract—**Mid-Carolina Electric Cooperative (MCEC) replaced their hydraulic reclosers with solid dielectric reclosers and microprocessor-based recloser controls as part of a program to modernize their distribution system. MCEC was having problems with hydraulic reclosers, including excess maintenance costs and poor repeatability of the time-overcurrent trip characteristic. As part of the replacement, they expected to solve these problems as well as reap the anticipated benefits of adding microprocessor-based relaying, including event reports, sequence of events recording, metering, and communication. What they did not expect to encounter was that, although the settings were the same as those used previously, several of the reclosers tripped on the fast curve due to inrush conditions. Adding the microprocessor-based relays made MCEC aware of this problem, which presumably existed all along. MCEC did not have the capability to detect the problem previously. After this discovery, MCEC engineers gathered event reports to allow them to characterize the inrush. This paper discusses those inrush events and ways to overcome undesired tripping on distribution feeders on inrush conditions using both settings changes and second-harmonic blocking.**

Index Terms—**Distribution Line Inrush; Microprocessor-Based Recloser Controls; Second-Harmonic Blocking; Solid Dielectric Reclosers.**

I. Introduction

Mid-Carolina Electric Cooperative (MCEC) is a not-for-profit electric distribution utility headquartered in Lexington, South Carolina. MCEC serves over 53,000 active meters serving member-owners who reside in Lexington, Richland, Newberry, Saluda, and Aiken counties. Over the years, MCEC has updated their protection schemes as load increased and new technologies became available. MCEC decided to replace their existing hydraulic reclosers with solid dielectric reclosers and microprocessor-based recloser controls as part of this program to modernize their distribution system. When they did so, they experienced multiple unintended operations of reclosers on the fast curve due to distribution line inrush.

This paper presents the MCEC reasoning for changing from hydraulic reclosers to solid dielectric reclosers with microprocessor-based recloser controls and their experience with unintended operations due to distribution line inrush. The paper then reviews the factors affecting transformer magnetizing inrush current on an electric distribution feeder circuit; presents the ways unintended operations can be prevented during feeder circuit energization, including settings changes and second-harmonic blocking; and outlines MCEC plans to address feeder circuit coordination in the future.

II. Application and Replacement of Hydraulic Reclosers

An example three-phase distribution circuit for the MCEC system is shown in Fig. 1. In the substation, primary protection is provided by a circuit breaker and feeder relay or, in some cases, by a recloser and microprocessor-based recloser control. A detailed description of MCEC substation design is covered in [1]. Downline reclosers are applied as shown. The downline reclosers were all previously hydraulic type with oil interruption. Tripping of hydraulic reclosers is initiated by a series trip coil that releases the stored-energy trip mechanism when an overcurrent occurs. A closing solenoid supplies the energy for contact closing and also stores energy in the trip mechanism. At MCEC, a three-phase tap can have three 70 A single-phase hydraulic reclosers while single-phase taps previously had either 50 A or 35 A hydraulic reclosers. Additional downline taps can be fused as shown in Fig. 1.

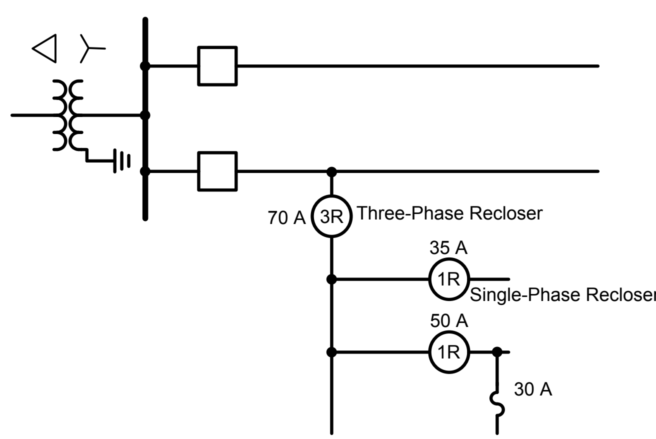

Fig. 1. Example MCEC distribution circuit.

All hydraulic reclosers in service prior to their replacement were set on two fast A curves and two slow B curves as shown in Fig. 2. This selection is the most widely applied method for setting hydraulic reclosers.

The purpose of the fast curve is to clear temporary faults using the recloser before the downstream fuse blows, thereby avoiding an extended outage to replace the fuse. Applying two fast trips allows for clearing two consecutive temporary faults, such as those that might occur during a heavy storm. Statistically, 90 percent of all distribution line faults clear during fast operations and 5 percent clear during slow operations, while 5 percent proceed to lockout due to a permanent fault [2].

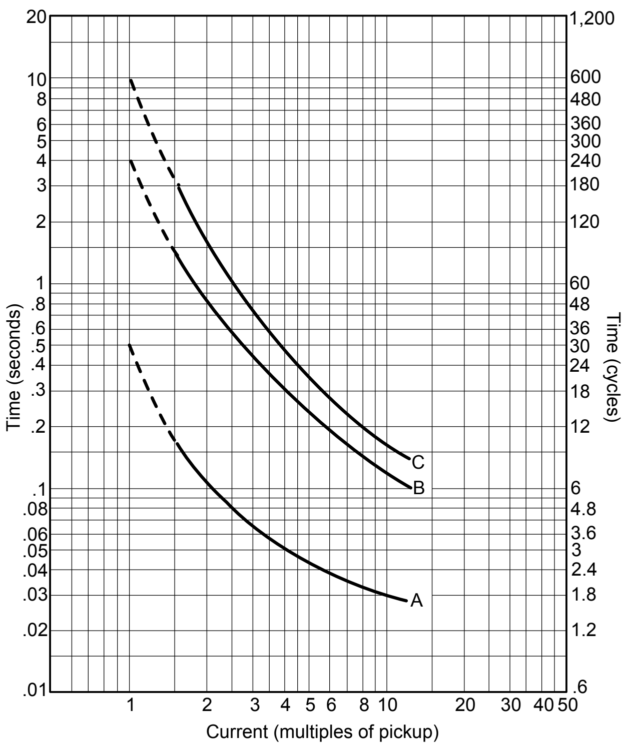

Fig. 2. Typical hydraulic recloser clearing curves.

The hydraulic reclosers on the MCEC system were all at least 20 years old. Experience showed that they needed to be sent to an outside maintenance shop every 3 to 4 years to maintain them and keep them operating properly. One manufacturer of MCEC reclosers was no longer in business, so MCEC did not have sufficient spares available to rotate their stock. They were forced into a situation where they had to evaluate purchasing new hydraulic reclosers or updating their protection schemes. They decided to move away from using hydraulic reclosers and purchased new solid dielectric reclosers with microprocessor-based recloser controls for the reasons described in the following subsections.

A. *Maintenance Costs*

As stated previously, the hydraulic reclosers needed to be sent to an outside maintenance shop every 3 to 4 years to maintain them and keep them operating properly. This cost roughly \$350 per recloser, plus parts, oil, and the time required by MCEC personnel to change them out. Condition-based maintenance was attempted according to IEEE standards [3] [4]. However, mechanical counters were found to be unreliable and estimating fault data was difficult.

In contrast, reclosers with solid dielectric insulation provide a relatively maintenance-free installation. Also, the operations counter and recloser wear calculations in the microprocessor-based recloser controls are precise.

B. *Coordination*

In MCEC experience, the coordination provided by the hydraulic reclosers was found to be less reliable than predicted by coordination studies and the performance of the reclosers was not repeatable. Operating time would increase over time after recloser maintenance was performed. Also, in spite of the clearing curve shown in Fig. 2, manufacturer literature states that the A characteristic curve provides no intentional time delay, thereby making coordination difficult between devices operating on the fast curve. In small reclosers where the current coil and its piston produce the opening of the contacts, a coordination margin of less than 2 cycles always results in concurrent operation, whereas a coordination margin of between 2 and 12 cycles may still result in concurrent operation [5]. This poor coordination in the slow curve resulted in unnecessary and prolonged outages due to poor selectivity and line crews not being able to accurately locate faults in a timely manner. Additionally, the reset times were not repeatable because they depended heavily on the viscosity of the recloser oil. Also, hydraulic reclosers do not provide for sequence coordination but microprocessor-based relays do.

The coordination provided by solid dielectric reclosers with microprocessor-based recloser controls is accurate and repeatable. The reset characteristic of these recloser controls is accurate and repeatable as well. Solid dielectric reclosers with microprocessor-based recloser controls can be coordinated more closely because there are no intrinsic errors caused by electromechanical mechanisms due to inertia, overspeed, and so on. There are numerous choices for coordination curves beyond the A, B, and C curves. Sequence coordination can be provided to keep reclosers in step for fast and delay curve operation, thus avoiding overtripping.

C. *Safety*

Manually operating of the hydraulic recloser and moving the nonreclose lever both must be done using a hot stick, with the operator standing directly beneath the recloser. This presents a danger to the operator should the recloser fail while being closed into a fault. Additionally, hot-line tagging is not available for hydraulic reclosers.

In contrast, solid dielectric reclosers with microprocessor-based recloser controls can either be operated remotely or on a time delay so that the operator is no longer required to stand beneath the recloser while it operates. No unwieldy hot stick is required, except when it is necessary to pull the yellow handle for visual confirmation of an open recloser. Hot-line tagging improves safety because absolutely no closing is allowed. Additionally, the tag may imply more sensitive tripping.

D. *Environmental Concerns*

The release of mineral oil from a hydraulic recloser requires cleanup, including contaminated soil removal, decontamination, and restoration.

However, solid dielectric reclosers contain no oil.

E. *Testing*

Current injection testing of the hydraulic reclosers requires a costly low-voltage, high-current test set not owned by MCEC. The recloser time-current characteristic could only be tested when outside maintenance was performed.

However, solid dielectric reclosers with microprocessor-based recloser controls can be tested using typical secondary injection relay test sets or even lower-cost recloser test sets. Also, microprocessor-based recloser controls do not require regular testing of the time-current characteristic because it does not drift.

F. *Additional Advantages*

The microprocessor-based recloser controls used by MCEC provide additional advantages, including the following:

- Forensic data, including event reports and Sequential Events Recorder (SER) data.
- Communication to each recloser control via an Ethernet network that provides both supervisory control and data acquisition (SCADA) communication and engineering access.
- Self-monitoring and alarm for control problems.

Additionally, the curve settings are simpler to change using the recloser control software instead of having to physically change out mechanical parts.

III. Initial Experience With Microprocessor-Based Recloser Controls

MCEC changed all their single-phase 35 A and 50 A hydraulic reclosers to solid dielectric reclosers with microprocessor-based recloser controls. More than 150 reclosers were changed in the process. Ethernet communication was established with the reclosers to alert the SCADA system of recloser operations and the availability of event report data. From this, an interesting trend was noticed—some circuits had unintended operations on the first or second trip of the fast curve when power was restored.

Two such recloser operations are shown in the raw (unfiltered) event reports in Fig. 3 and Fig. 4. This microprocessor-based recloser control replaced a 50 A hydraulic recloser and has a minimum pickup of 100 A primary with the A curve selected for the two fast trips. Fig. 3 shows a first trip occurring due to a lightning strike, which was followed by the subsequent clearing of a downstream 1.5 A transformer fuse. Fig. 4 shows a second trip due to distribution line inrush after the recloser closed.

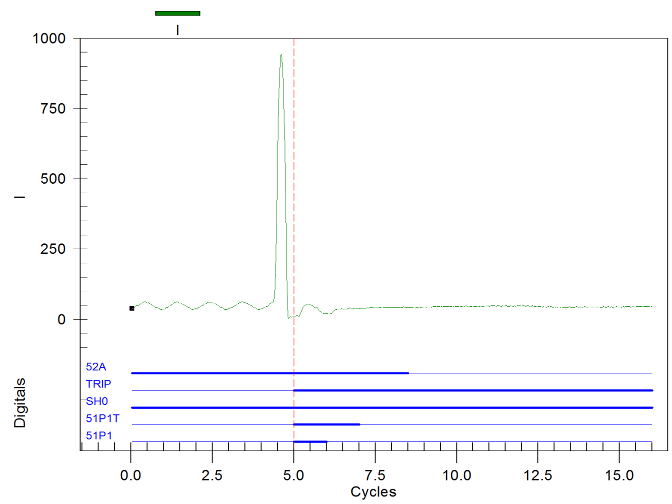

Fig. 3. First recloser trip due to lightning strike and fuse clearing.

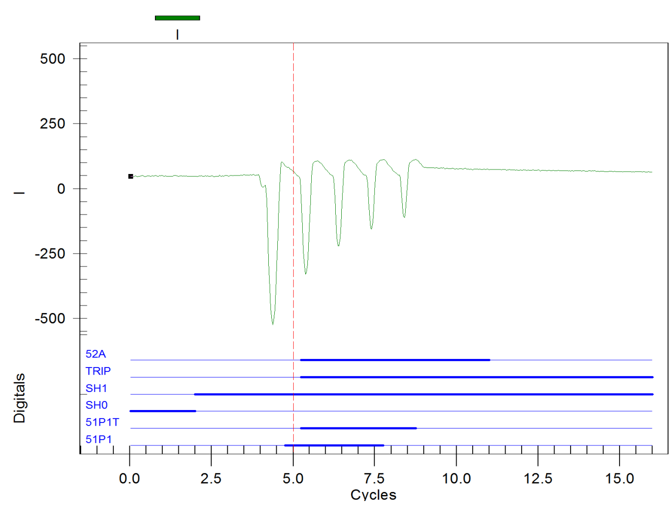

Fig. 4. Second recloser trip on distribution line inrush.

In both cases, tripping occurs very quickly. Fig. 5 shows the A, B, and C curves of the microprocessor-based relay. Note that the A curve operates in about 1 cycle at high magnitudes of current. This is a recloser operate curve as opposed to a clearing curve. It is designed to allow sufficient time for the recloser to then respond and clear the fault in a manner similar to the hydraulic recloser clearing curve shown in Fig. 2.

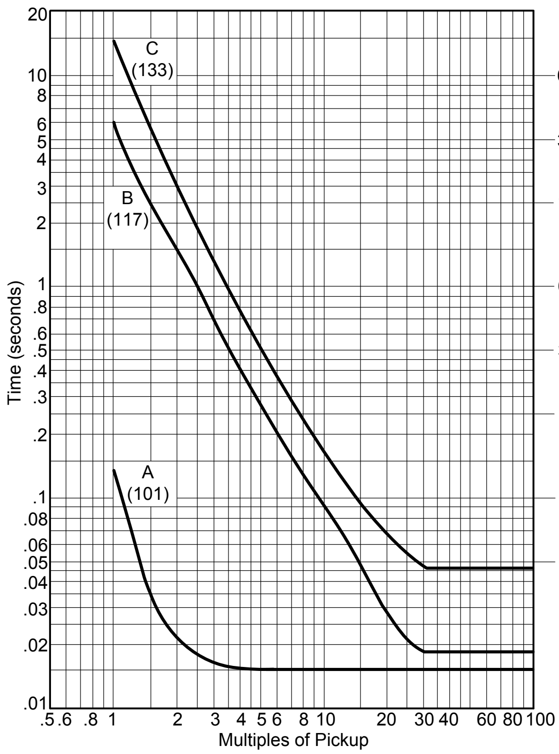

Fig. 5. Microprocessor-based recloser control operate curve.

The recloser control overcurrent elements operate on current signals after going through a 1-cycle cosine filter. The actual filtered signals and their magnitudes are shown in Fig. 6 and Fig. 7.

For the first event, shown in Fig. 6, the pickup of the fast curve (51P1) is shown to coincide with it timing out (51P1T). In actuality, for these quick events, the timing element starts before 51P1 asserts. Looking at the beginning magnitude of the current (IMag) in Fig. 6, it is apparent that 51P1T for the first event timed out in 0.5 cycles, which is still within the relay specifications. Also, according to the recloser auxiliary contact (52A), the recloser opened in roughly 3.5 cycles, for a total clearing time of 4 cycles. The magnitude of the fault was 390 A, or about 4 times minimum pickup. The total clearing time for the hydraulic recloser, as shown in Fig. 2, is about 3 cycles. Therefore, if 52A is a good indication of fault clearing, the solid dielectric recloser with microprocessor-based recloser control was about 1 cycle slower than the hydraulic recloser would have been for this event. In any case, it is comparable in speed.

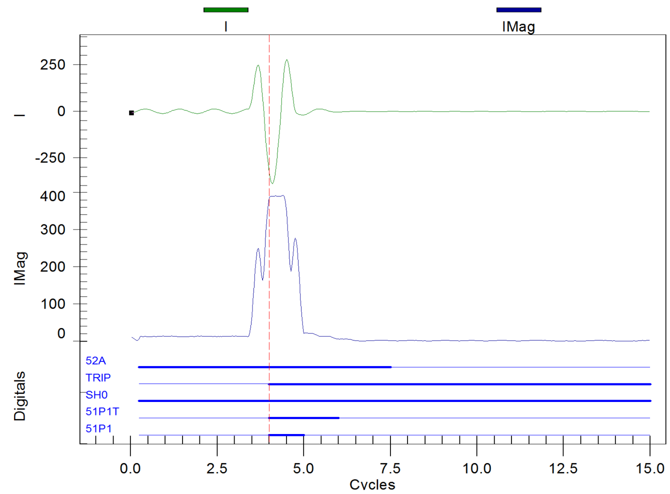

Fig. 6. Filtered event report for first recloser trip.

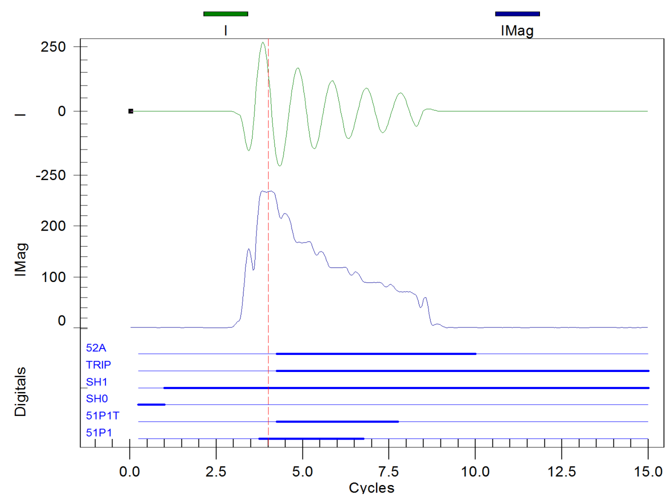

Fig. 7. Filtered event report for second recloser trip.

Looking at the beginning of IMag in the second event shown in Fig. 7, it is apparent that 51P1T timed out in 1 cycle after the increase in current. This delay is identical to the A curve shown in Fig. 5. The magnitude of the fault was about 250 A, or about 2.5 times minimum pickup. The total clearing time for the hydraulic recloser, as shown in Fig. 2, is about 4.8 cycles. Looking at Fig. 4, the solid dielectric recloser with microprocessor-based recloser control also took about 5 cycles to clear.

There were numerous events similar to these collected on various microprocessor-based recloser controls due to pickup of the fast curve on distribution line inrush and many trips as well. They could occur on the first and second trip due to source re-energization after an outage or only on the second trip following a temporary fault. Either way, they resulted in unnecessary blinks of customer power. The event reports for this phenomenon became so numerous that MCEC stopped collecting and analyzing all event reports on single-phase reclosers for a time.

It seemed evident that, because their timing is similar, this had been occurring all along with the hydraulic reclosers but had been unnoticed for many years because the hydraulic reclosers lacked the event reporting and communication afforded by the microprocessor-based recloser controls. This was not a new or previously unconsidered phenomenon. Distribution seminar notes reviewed by MCEC from 1984 state, "There is an argument that a recloser rarely closes in and holds on second fast operations due to inrush current" [2]. It was MCEC opinion that, although this might have been acceptable before the widespread use of microprocessor-based devices, it is not acceptable for customers today. Therefore, MCEC engineers set out to find a solution to this problem.

IV. Feeder Circuit Inrush

An electric distribution feeder circuit experiences a magnetizing inrush current that is the sum of the inrush of all the transformers in that circuit. Maximum inrush current on a transformer is caused whenever the residual flux in the transformer is a maximum of one polarity and, when energizing the device at a voltage zero crossing, the normally required value of steady-state flux is a maximum of the opposite polarity. This is shown in Fig. 8. Note also that if the transformer is energized at the point where the steady-state flux value equals the residual flux value, no transient flux is present and there is no magnetizing inrush current [6] [7].

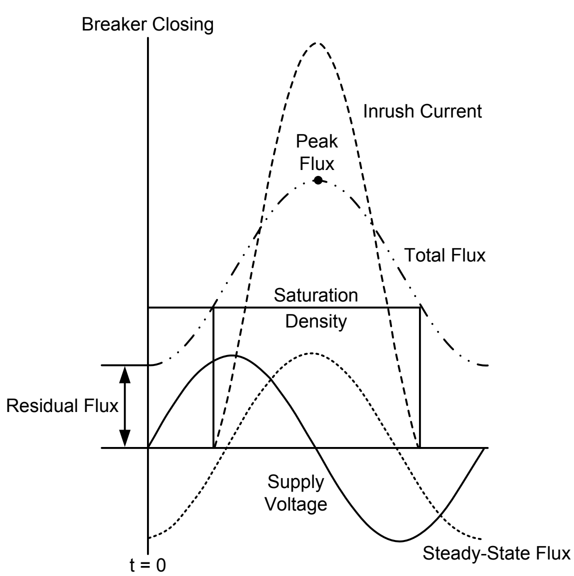

Fig. 8. Transformer inrush with respect to supply voltage and flux.

It is easily seen that this effect is highly random and dependent on where on the sine wave the transformer is de-energized and then re-energized. Many operations can take place before a worst-case magnetizing inrush current is experienced.

The sine wave switching phenomenon shown in Fig. 8 not only impacts the magnitude of the inrush current but its waveshape as well. Magnetizing inrush current waves have various waveshapes. A typical wave appears as a rectified half wave with decaying peaks. The event shown in Fig. 4 is a good example of this. As shown in Fig. 8, inrush current begins to flow when the device core saturates. This inrush current is limited only by the system impedance and the impedance the coil would have with the core removed. This results in waveforms that have varying amounts of harmonic distortion according to the amount of residual flux in the transformer and where on the voltage sine wave the transformer is energized. For this reason, the magnitude of second and fourth harmonics has been used to block or restrain differential elements for many years. Recently, second-harmonic blocking has also been added to feeder protection relays and recloser controls to prevent unintended operation when energizing a distribution feeder circuit.

V. Mitigating Undesired Operation During Inrush Using Settings Changes

Traditionally, the primary method to make inverse-time overcurrent (51) relays secure during distribution line inrush was to raise the pickup, increase the time delay, or both. While this might prove effective for preventing tripping during inrush, it decreases the sensitivity and speed of operation.

As part of preparing this paper, different available fast recloser curves were tested in the laboratory to see if they would ride through the distribution inrush event shown in Fig. 4 without tripping. The tested curves included 4, R, N, 17, and 1 with time dial TD = 1 and Curve A with TD = 2, as shown in Fig. 9. Also shown in Fig. 9 is a 20T fuse for reference.

The test results shown in Table I along with the curves shown in Fig. 9 demonstrate that changing the curve setting of the fast curve can be used to successfully mitigate undesired operation due to distribution line inrush and still prevent downline fuses from blowing. This requires additional options for fast curve selection, such as those available in a microprocessor-based recloser control. Changing the curve settings to successfully mitigate undesired operation due to distribution line inrush can be accomplished provided the utility is able to characterize the inrush characteristic for its distribution lines.

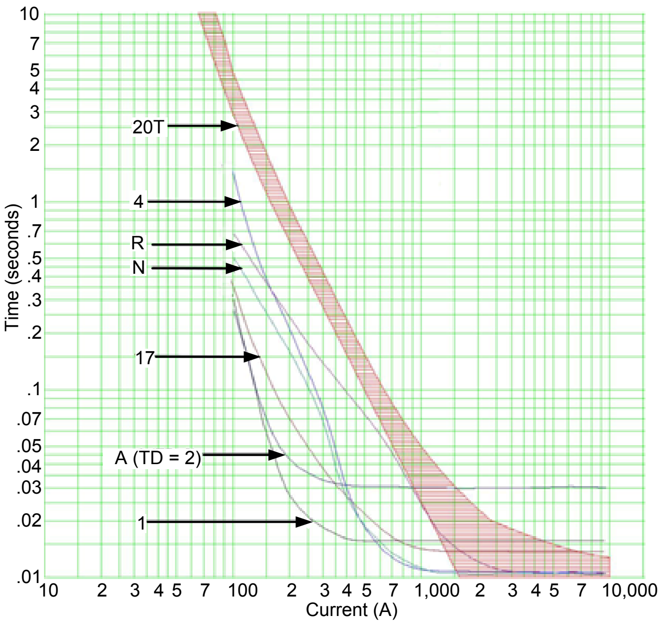

Fig. 9. Fast curves tested with distribution line inrush.

TABLE I
FAST CURVE TRIP TESTS

Curve	Trip
4	No
R	No
N	No
17	No
1	Yes
A (TD = 2)	Yes

Note, however, that the tested distribution inrush event shown in Fig. 4 is not necessarily a worst-case event because of the high variability of transformer inrush as described in Section IV. So the tests performed are interesting but not entirely adequate for determining how to prevent undesired operation due to distribution line inrush. More complex tools such as an Electromagnetic Transients Program (EMTP) or real-time digital simulation could be used; however, this is too costly to be practical for many users.

VI. Mitigating Undesired Operation During Inrush Using Second-Harmonic Blocking

Changing the recloser curve settings was considered by MCEC, but the idea was discarded because a better option for mitigating undesired operation during distribution line inrush was available with the applied microprocessor-based recloser controls. This is because the recloser controls were provided with second-harmonic blocking logic. Using second-harmonic blocking means that MCEC does not have to slow down the fast curve, nor do they have to completely characterize the inrush on their distribution lines in order to raise their fast curve settings.

The harmonic currents for the events shown in Fig. 3 and Fig. 4 are shown in Fig. 10 and Fig. 11, respectively. It can be seen by looking at Fig. 10 that what is essentially a pulse in Fig. 3 is rich in harmonics, as would be expected. The magnitude of the second harmonic is 87.5 percent of the fundamental. The distribution line inrush from Fig. 4 can be seen to contain about 57 percent second harmonic. Both of these events appear to be good candidates for applying second-harmonic blocking.

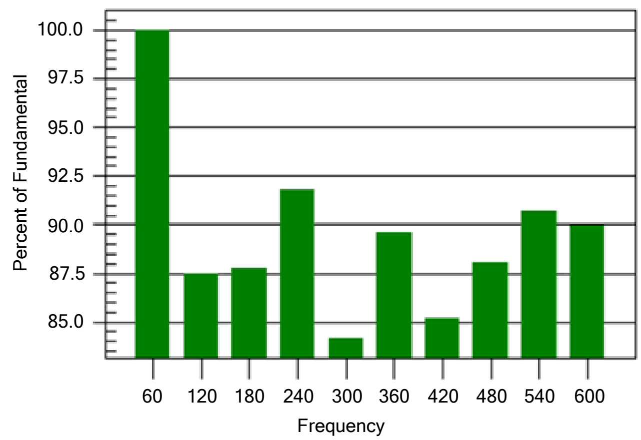

Fig. 10. Harmonics for first recloser trip due to lightning strike and fuse clearing.

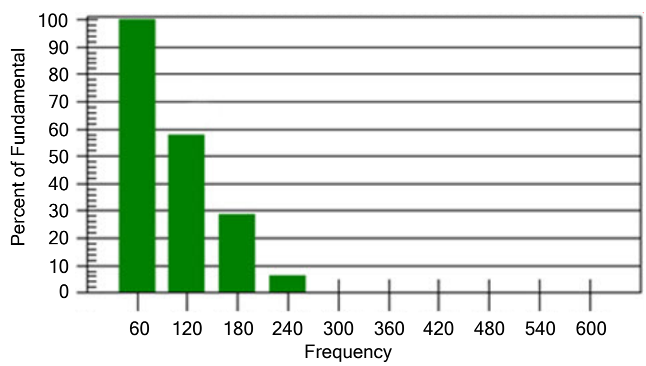

Fig. 11. Harmonics for second recloser trip on distribution line inrush.

The logic for the second-harmonic blocking applied by the recloser control is shown in Fig. 12. The second-harmonic blocking logic uses the ratio of the second-harmonic content of the recloser single-phase current to the fundamental current to calculate the percent second-harmonic content. When the torque-control setting evaluates to logical 1, if the second harmonic exceeds the adjustable pickup threshold for the pickup time delay, the second-harmonic blocking output asserts. Once the output is asserted, if the second-harmonic content falls below the threshold for the dropout time delay, the output deasserts.

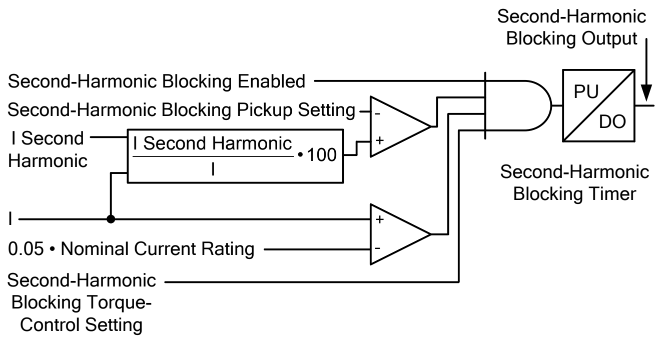

Fig. 12. Second-harmonic blocking logic.

MCEC enabled the second-harmonic blocking on a few of the reclosers that had experienced tripping on distribution line inrush. They set their second-harmonic blocking to pick up at 15 percent of fundamental current with no intentional pickup or dropout time delay. The second-harmonic blocking output was then used in the torque-control equation of the fast curve to keep it from operating on distribution line inrush. After MCEC did this, they experienced no more undesired operations of those circuits due to distribution line inrush.

A test of these settings was performed in the laboratory as part of preparing this paper. The MCEC settings were loaded into an identical recloser control, and the events shown in Fig. 3 and Fig. 4 were injected into the recloser control using a relay test set. The results of these tests are shown in Fig. 13 and Fig. 14. It can be seen that for both tests, the second-harmonic blocking output (HBL2T) is active and the fast curve does not pick up (51P1) or time out (51P1T). Additionally, the slow curve picks up (51P2) but does not time out (51P2T).

Additionally, there are three-phase reclosers used in some MCEC substations for feeder protection. Recently installed microprocessor-based recloser controls have second-harmonic blocking enabled with similar settings to the single-phase recloser controls. An example distribution line inrush event from one of these reclosers is shown in Fig. 15. The trip is set at 400 A, so there is no danger of an undesired operation for this event. We can see that the recloser control could block tripping due to the second-harmonic blocking element asserting for the A-phase. This particular actuation, however, is not caused by a high second harmonic from distribution line inrush. The Fourier transform interprets this step change in the fundamental frequency current as containing harmonics, and the second-harmonic blocking element asserts briefly. This second-harmonic blocking element then quickly deasserts and has no adverse effect on the protection provided by the time-delayed overcurrent element.

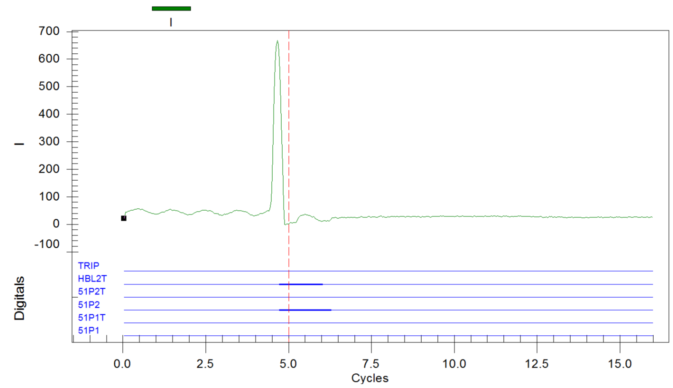

Fig. 13. Test of second-harmonic blocking for lightning strike and fuse clearing.

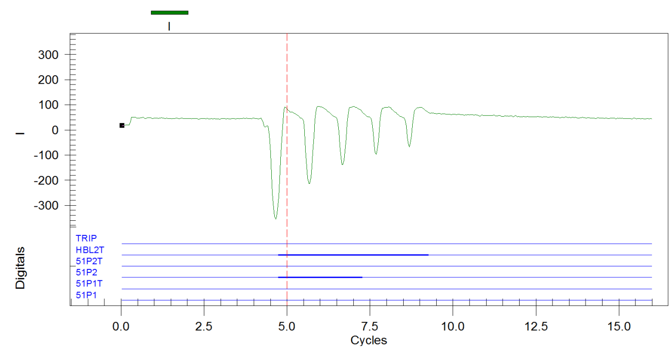

Fig. 14. Test of second-harmonic blocking for distribution line inrush.

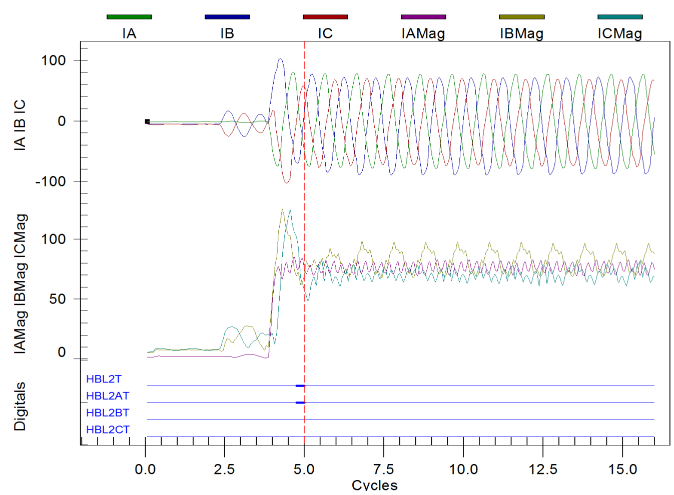

Fig. 15. Three-phase distribution line inrush at the substation.

It should be noted that current transformer (CT) saturation during faults can also cause the recloser control to measure second-harmonic current. This can cause the second-harmonic blocking element to prevent tripping when it is needed. This has to be considered as part of any design where the second-harmonic blocking element is employed. One method is to set an unsupervised element above the expected inrush current to provide fast protection during large faults. In the case of these reclosers, the slow curve is still available to clear the fault. Also, with the applied 1000:1 CT, fault currents in the 1,000 to 2,000 A range, and the low X/R ratios seen on a distribution feeder, it seems unlikely that CT saturation will occur. Per the manufacturer, the CT resistance is 6.9 Ω. Assuming 30 feet of 18 AWG cable at 0.005 Ω per foot, the resistance of the recloser control cable would be 0.3 Ω. The CT burden voltage for a 2,000 A fault would be 2 • (6.9 + 0.3) = 14.4 V. This is well within the linear part of the excitation curve shown in Fig. 16, so saturation is not expected.

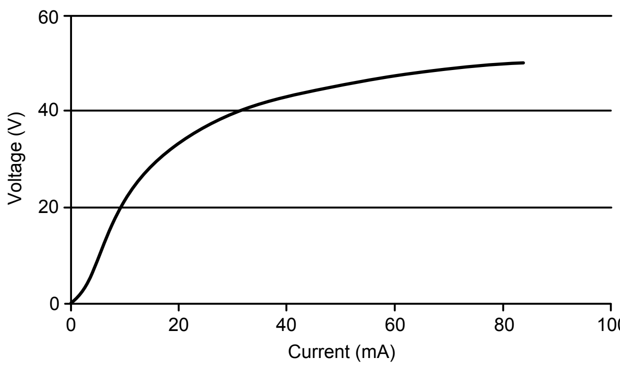

Fig. 16. Recloser 1000:1 A excitation curve.

VII. Path Forward for System Coordination

At the time of writing this paper, only the single-phase hydraulic reclosers have been converted to solid dielectric reclosers with microprocessor-based recloser controls. Three-phase 70 A solid dielectric reclosers with single-pole tripping have been ordered and will be installed soon. All are planned to have second-harmonic blocking enabled.

MCEC is also adding feeder relaying for their substation circuit breakers that incorporates second-harmonic blocking. It is their intention to enable this feature where they are applied as well.

After all hydraulic reclosers are replaced, MCEC plans to look again at protection device coordination. Because they will have an abundance of different time-coordination curves to choose from, as opposed to only A, B, and C, they intend to see what they can do to improve coordination on their system. The applied recloser controls offer five U.S. and IEC relay curves as well as 38 recloser curves with time dial. Also, the time-coordination curves can be set as complex curves with the selection of constant time adder, vertical multiplier, and minimum response time settings to speed up or slow down operation. Additionally, ground elements are available for the three-phase recloser control. These could be set more sensitively but, depending on the available fault current at the fault location, may not coordinate with the downline reclosers and fuses.

Note that curves that may have seemed to coordinate on a hydraulic recloser may not coordinate with a microprocessor-based recloser control. In Fig. 5, the A curve has a flat 1-cycle operate time beyond 5 multiples of pickup. Compare this to Fig. 2, which is not flat. It becomes evident that if a distribution circuit has an available short-circuit current beyond 5 times pickup, two microprocessor-based recloser controls with simple A curves applied certainly will not coordinate. (Although, as described previously, it is difficult or impossible to coordinate two hydraulic reclosers both set on the A curve.) Therefore, it is important to revisit coordination when applying microprocessor-based recloser controls rather than just applying them with the same settings used with the hydraulic reclosers.

One place MCEC is interested in improving coordination is between the A recloser curve and 1.5 A dual-element transformer fuses. MCEC is of the opinion that it is not desirable to blink an entire tap rather than blowing an individual distribution transformer fuse. It can be seen in Fig. 17 that an A curve on a microprocessor-based recloser control with 70 A pickup does not coordinate with a 1.5X fuse. Note, however, that some of these events can be prevented using second-harmonic blocking as shown in Fig. 13.

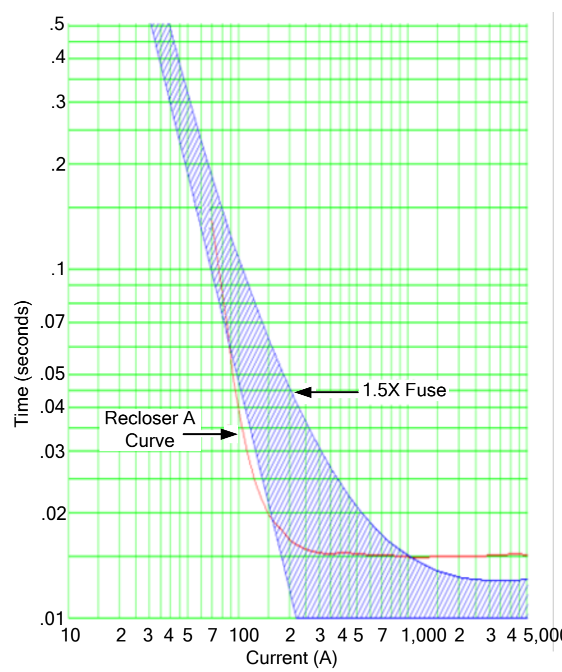

Fig. 17. Recloser fast curve coordination with transformer fuse.

VIII. Conclusion

MCEC is in the midst of modernizing their distribution system. One item that had to be addressed was how to apply downline reclosers in the future. They decided to move away from using hydraulic reclosers and are replacing them with new solid dielectric reclosers with microprocessor-based recloser controls. This has provided many benefits with regard to maintenance, coordination, safety, the environment, testing, monitoring, and communication. One advantage MCEC did not foresee was that they would be able to eliminate unnecessary blinks of their distribution circuits due to distribution line inrush using second-harmonic blocking.

IX. References

[1] L. Ayers, M. Lanier, and L. Wright, "Protecting Distribution Substation Assets – Modern Protection Schemes With Microprocessor-Based Relays," proceedings of the 66th Annual Conference for Protective Relay Engineers, College Station, TX, April 2013.

[2] McGraw Edison Power Systems Division, "Overcurrent Protection for Distribution Systems – Seminar Notes," May 1984.

[3] IEEE Standard C37.60-2003, IEEE Standard Requirements for Overhead, Pad-Mounted, Dry Vault, and Submersible Automatic Circuit Reclosers and Fault Interrupters for Alternating Current Systems up to 38 kV.

[4] IEEE Standard C37.61-1973, IEEE Standard Guide for the Application, Operation, and Maintenance of Automatic Circuit Reclosers.

[5] H. Hosseinzadeh, University of Western Ontario, "Distribution System Protection ES586B: Power System Protection," May 2008. Available: http://www.eng.uwo.ca/people/tsidhu/Documents/ES586B-Hesam%20 Hosseinzadeh-250441131.pdf.

[6] W. K. Sonnemann, C. L. Wagner, and G. D. Rockefeller, "Magnetizing Inrush Phenomena in Transformer Banks," *Transactions of the American Institute of Electrical Engineers Part III: Power Apparatus and Systems*, Vol. 77, Issue 3, April 1958, pp. 884–892.

[7] D. Boyd, T. Saunders, M. Lanier, and L. Wright, "Providing Secure Ground Protection for Electric Arc Furnaces During Inrush Conditions," proceedings of AISTech 2012 – The Iron & Steel Technology Conference and Exposition, Atlanta, GA, May 2012.

X. Biographies

Larry Wright, P.E., received a BS in Electrical Engineering in 1982 from North Carolina State University. From 1982 until 2003, he worked for Duke Energy, designing nuclear, hydroelectric, and fossil-powered generating stations for Duke Energy and other utilities and independent power producers. From 2003 to 2005, Larry served as the subject matter expert on protective relaying for Duke Energy generating stations. He joined Devine Tarbell Associates in 2005 as manager of electrical engineering, providing consulting services to the hydroelectric industry. In 2008, he joined Schweitzer Engineering Laboratories, Inc., where he is presently employed as a field application engineer. Larry is a registered professional engineer in the states of North and South Carolina.

Lee Ayers received a BS in Electrical Engineering from Clemson University in 1982. From 1982 until 1986, he worked for Central Electric Power Cooperative in Columbia, South Carolina. Since 1986, he has been employed with Mid-Carolina Electric Cooperative in Lexington, South Carolina, managing substations, metering, system control and dispatch, and outside plant communications. Most recently, he was promoted to Vice President of Engineering.

Previously presented at the 2015 Texas A&M Conference for Protective Relay Engineers and the 2015 IEEE Rural Electric Power Conference.

20141212 • TP6651-01