Frequency Tracking Fundamentals, Challenges, and Solutions

David Costello and Karl Zimmerman
Schweitzer Engineering Laboratories, Inc.

This paper was presented at the 64th Annual Conference for Protective Relay Engineers, College Station, Texas, April 11–14, 2011, and can be accessed at: http://dx.doi.org/10.1109/CPRE.2011.6035621.

Frequency Tracking Fundamentals, Challenges, and Solutions

David Costello and Karl Zimmerman, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—How stable is the frequency of the power system on a given day? How does a microprocessor-based relay track power system frequency? Why is frequency tracking important?**

This paper reviews the fundamentals of frequency tracking and explains, in practical terms, how and why this is done in digital relays. The performance of protective elements at off-nominal frequencies is of key interest.

As with all technical areas, designs have evolved over time. This paper also documents the evolution of different designs, exploring each design's merits and why it was implemented.

Real-world power system events are used to highlight scenarios that challenge designs. Lessons learned from event analysis are shared. Practical solutions and application advice are provided for each case study.

I. What Does a Day in the Life of Power System Frequency Look Like?

A sinusoidal signal varies with time and is periodic. The period, T, of the signal is the length of time in seconds that it takes for the sinusoid to pass through all of its values. The reciprocal of T gives the frequency, *f*, of the signal in cycles per second, or hertz (Hz).

Using a cosine function, the sinusoidal voltage signal in Fig. 1 may be represented by (1).

$$V(t) = |Vm| \cos(\omega t + \varphi) \tag{1}$$

where:

$V(t)$ = sinusoidal voltage signal.

$|Vm|$ = peak or maximum amplitude of V(t) in volts.

ω = omega, angular frequency in radians per second ($2\pi / T = 2\pi f$).

t = time in seconds.

φ = phi, angle in degrees that determines V(t) at t = 0.

Remember that ωt (radians) and φ (degrees) must carry the same units before being added in the argument of the cosine function. 2π radians equals 360 degrees [1].

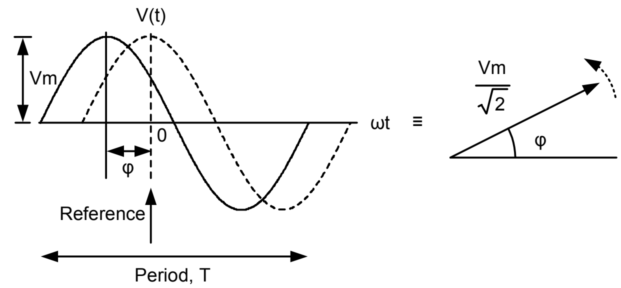

Fig. 1. A sinusoidal signal

In theory only, there exists a steady state whereby total generation equals total load plus losses. In this state, machine speeds are nearly equal to the synchronous speed at the system nominal frequency (i.e., 60.0 Hz).

Interconnected power grids are amazingly large and complex machines, however, and in practice, frequency ebbs and flows within moderate boundaries. System frequency changes constantly based on system dynamics and mismatch between generation and load. In response, small corrections are made by automatic generator controls and operators to maintain near-nominal frequency. Consider a day in the life of a real power system. Fig. 2 is the actual system frequency of the Electric Reliability Council of Texas (ERCOT), plotted each minute during a 24-hour period on January 18, 2010 [2].

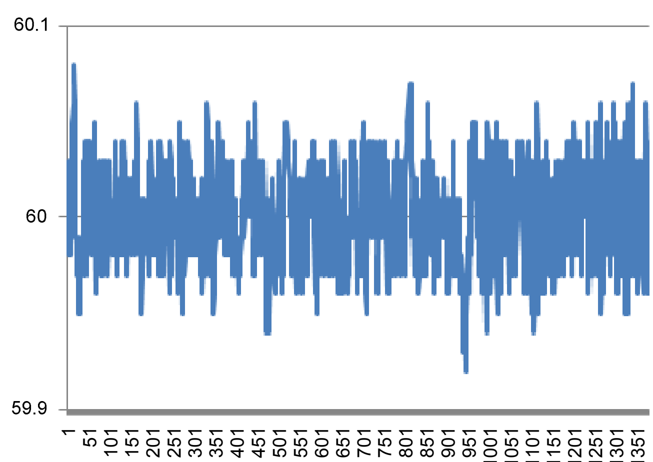

Fig. 2. ERCOT system frequency each minute on January 18, 2010 [2]

Beyond normal system dynamics, problems of one sort or another can also create frequency changes. An interesting oscillation on the ERCOT system occurred on March 31, 2009. Fig. 3 shows superimposed frequency data from two phasor measurement units (one in West Texas and the other in Austin). A sustained 0.067 Hz oscillation lasted for 15 minutes. A lignite unit was undergoing mechanical valve freedom-of-movement testing. During the test, a throttle valve became stuck [2].

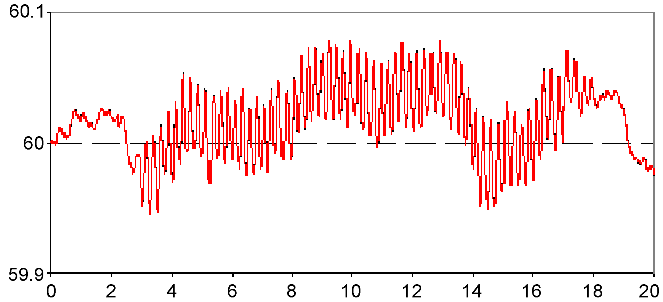

Fig. 3. ERCOT system frequency during 20 minutes on March 31, 2009

Equipment has varying sensitivity to off-nominal frequency operation. Steam turbine blades, for example, are designed to have their natural frequency significantly differ from the system nominal frequency and harmonics to avoid mechanical resonance, which can cause stress and damage. Great care is taken through protective relaying to ensure that operation is restricted at off-nominal frequencies [3].

When generators are at or nearly at equilibrium, the frequency is the same at all points on the interconnected network. During power system disturbances, however, local phase angles and frequency undergo changes. Equation (2) expresses frequency in terms of system nominal frequency and rate of change of local rotor angle [4].

$$f1 = f0 + \frac{1}{2\pi}\frac{d\sigma}{dt} \quad (2)$$

where:

$f1$ = new local frequency.

$f0$ = system nominal frequency.

$\frac{d\sigma}{dt}$ = rate of change in rotor angle, σ, in radians per second.

Fig. 4 shows the frequency response at one point in ERCOT when a 789 MW unit tripped offline on January 26, 2010. Immediately after the unit trip, frequencies across ERCOT differed slightly. Within 2 minutes, normal controls had restored the system to predisturbance frequency [2] [5].

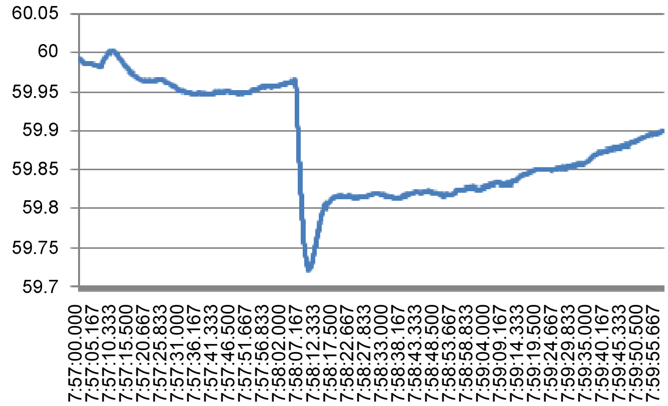

Fig. 4. ERCOT system frequency 7:57 to 8:00 UTC on January 26, 2010

The relative phase angle of West Texas, with respect to Austin, is shown in Fig. 5. On February 23, 2009, the voltage angle of West Texas dropped by 3.5 degrees, indicating that there was a unit trip in West Texas. The synchrophasor data were confirmed by the ERCOT daily grid operations report. A 668 MW unit tripped, which induced a 0.65 Hz damped oscillation before a new system equilibrium was reached. The system frequency during this event dropped to 58.2 Hz, oscillated over a period of 1 minute, and then slowly recovered to 60 Hz [2] [5].

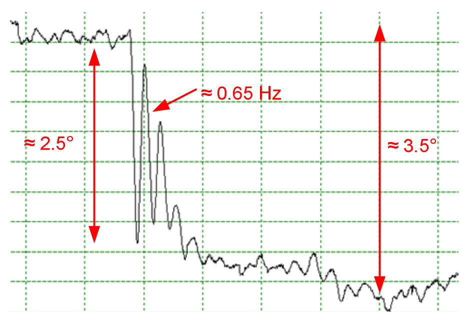

Fig. 5. Voltage phase angle of West Texas with respect to Austin

Larger disturbances require more drastic response measures. To restore the system to nominal frequency during large disturbances, grid control authorities mandate automatic load shedding. For example, ERCOT requires 5 percent of the total load be tripped at 59.3 Hz within 40 cycles or less [6].

During severely unstable oscillations, power can flow across a system like water sloshing in a bathtub. In the August 14, 2003, blackout, enormous power swings, angular instability, and frequency fluctuations occurred. Fig. 6 shows generation in the Detroit area (in blue) becoming out of step, losing synchronism, and slipping poles [7]. Protective relays and controls are required to detect these conditions and separate at appropriate locations and times.

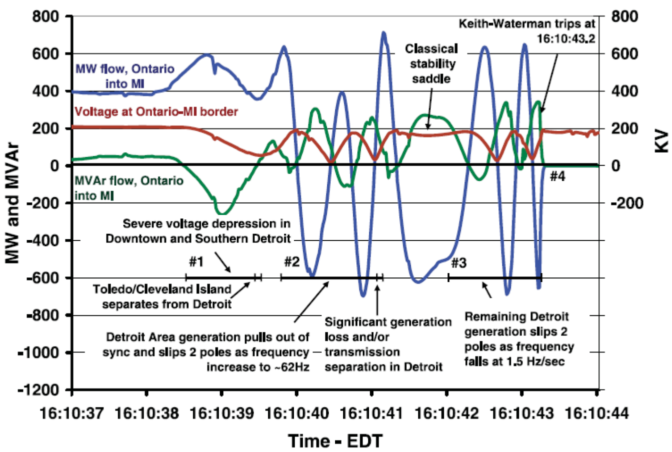

Fig. 6. Slipped pole/system separation [7]

II. Why Track Frequency, and How Is It Done?

Microprocessor-based (µp) relays sample voltage and current signals at some defined rate. Methods include the following:

- Sample rate (4 or 16 samples per cycle) is a function of the *nominal* power system frequency (e.g., 60 Hz, configured by the user through a model number or a setting).
- Sample rate is a function of the measured (estimated) power system frequency.
- Sample rate is not a function of the power system frequency (e.g., 8 kHz in the time domain).

Protection functions within µp relays are based on sampling that is *some* function of the power system frequency. Relays that use fixed 8 kHz time-domain sampling do so for high-resolution oscillography and COMTRADE files; however, the raw data are resampled at the estimated power system frequency prior to use by protection algorithms.

Quartz crystal oscillators or a Global Positioning System satellite-synchronized IRIG-B signal can provide a repeating time pulse for sampling and other timekeeping within the relay.

A digital filter, such as a 16-tap one-cycle cosine filter, is then applied within the µp relay to the input signals. As long as the sampling provides an integer number of samples per cycle, the filter operates as expected. Fig. 7 shows how four samples taken during one cycle of a 60 Hz signal are used to determine the time-varying waveform and phasor magnitude and angle.

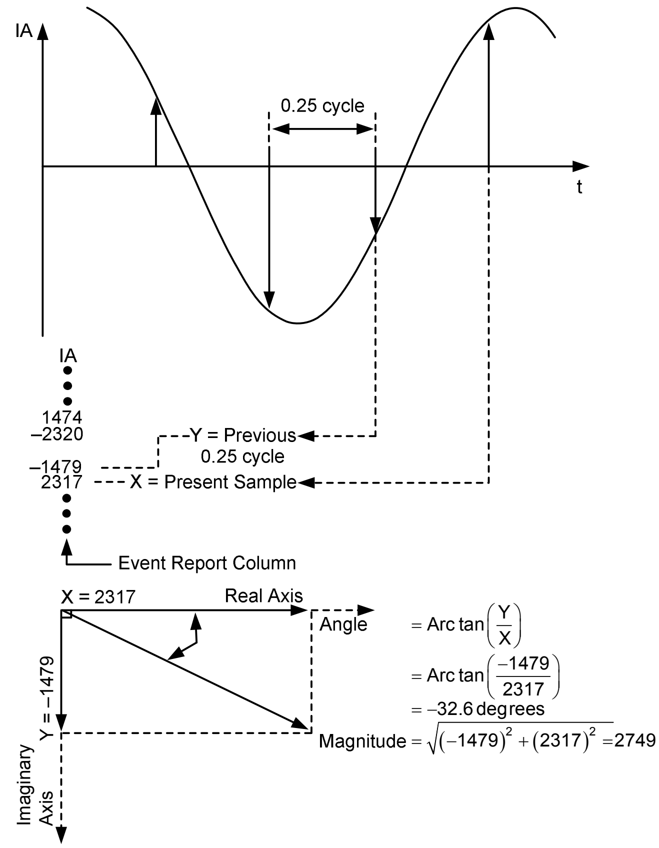

Fig. 7. Consecutive 0.25-cycle samples as X–Y phasor components

When there is a difference between actual frequency and sampling frequency, errors develop. A rule of thumb is that there is a 2 percent magnitude and phase angle ripple for every 1 Hz difference between actual and sampling frequencies. Consider Fig. 8. An induction motor is connected and running at full mechanical load. A relay is tracking frequency from the source-side voltage connected to the VS1 input. The relay also measures the motor bus-side voltage as VA. At 12.375 cycles, the main breaker is opened, disconnecting the motor from the source.

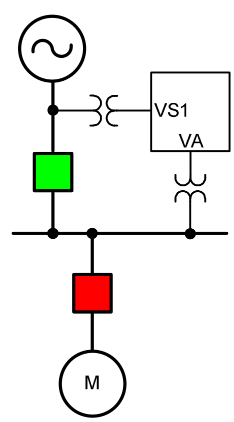

Fig. 8. An example system measures two different frequencies

The induction motor maintains a voltage on the motor bus that decays in magnitude and frequency. See Fig. 9. The oscillation in VA magnitude in the relay report is an error caused by the difference between actual and sampling frequency: the relay is sampling VA based on the 60 Hz VS1 signal, but the motor bus is not alternating at 60 Hz after the main breaker opens.

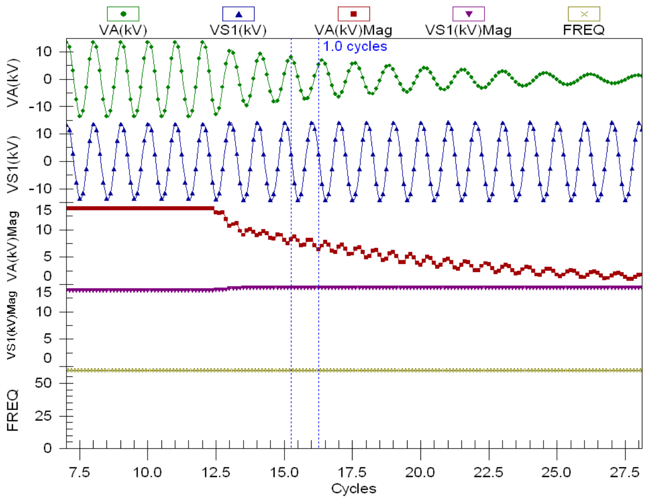

Fig. 9. VA motor bus voltage magnitude error

Recall from Fig. 1 that period, T, is the time between like zero crossings. How do we establish a zero crossing?

Linear interpolation can accurately find the moment a signal crossed zero given two points, a known time difference between points, and a high enough sampling rate, as shown in Fig. 10.

$$t = S\left(\left|X_{n-1}\right| / Y\right) \tag{3}$$

where:

$X(n)$ = the current sample.

$X(n-1)$ = the previous sample.

t = fraction of one sampling period before the signal crossed zero.

S = sampling period.

Y = difference in magnitude between the sampled points, $X(n)-X(n-1)$.

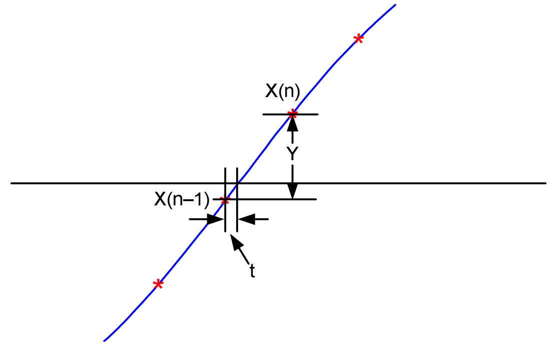

Fig. 10. Using linear interpolation to determine zero-crossing time

Some algorithms require sample X(n) to be *greater* than *z* • VNOM (the nominal phase voltage) and X(n–1) to be *less* than *z* • VNOM, where *z* is a design constant. In Fig. 11, VNOM in the relay was incorrectly set to 67 V secondary on a 208 V system. With VNOM set too low, occasionally the relay will not get two consecutive samples with one above and one below the threshold. Therefore, the relay misses zero crossings and calculates the wrong frequency. Signal magnitude and phase angles are therefore in error.

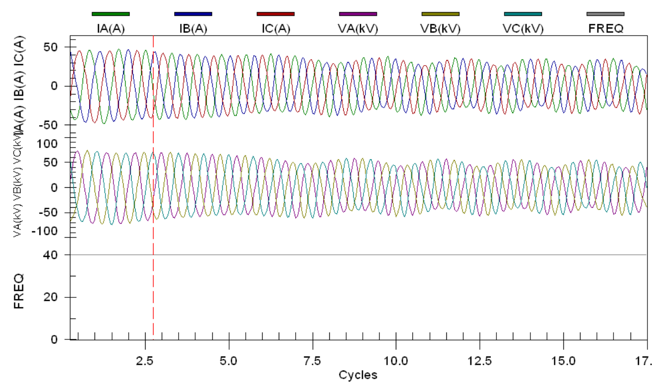

Fig. 11. Frequency tracking error due to incorrect VNOM setting

Voltage signals are generally preferred for frequency tracking. Some relays use VA voltage. Still others may use V1 or a similar composite signal such as Vα, where:

$$V\alpha = \left[VA - (VB + VC)/2\right] \bullet m \tag{4}$$

where:

m = a design constant.

If VA or all three voltages fall too low, relays generally revert to the nominal frequency after a time delay. In some relays, a voltage signal is ignored if that phase has a pole-open condition. For special applications, some relays allow the user to specify a primary and alternate voltage source for frequency estimation.

Fig. 12 shows an induced and ringing voltage on VA during an open-pole (A-phase) condition on a 102-mile-long 345 kV transmission line. VA comes from line-side capacitive voltage transformers (CVTs). A backup relay that tracks frequency from VA alone misoperated. The primary relay that tracks frequency from Vα operated correctly. A temporary solution is to force VA to zero with a breaker 52A contact during open-pole conditions; with VA forced to zero, the backup relay will default to nominal frequency and not misoperate.

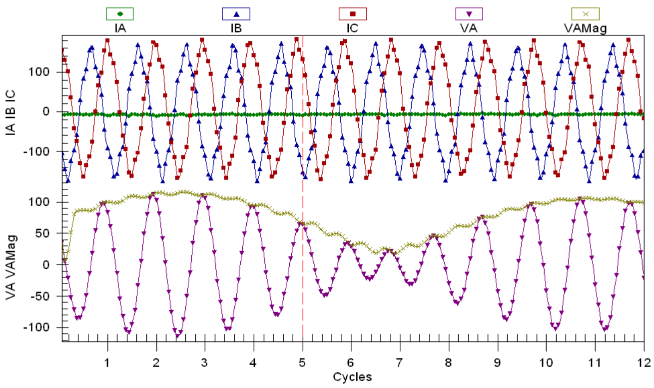

Fig. 12. Induced line-side VA voltage during open-pole condition

Low load, open circuits, and fault-caused dc offset can make zero-crossing detection with current signals less reliable. Currents are used in relays without voltage inputs. Others use VA unless that signal becomes too low in magnitude; then the relay may switch to I1.

An Olympic filter takes the latest four period estimates, throws out the high and low, and averages the remaining two. This is used as the qualified period, P. An infinite impulse response (IIR) filter then generates the new sampling period, SP_n, based on some ratio, such as:

$$SP_n = kSP_{n-1} + (1-k)P \tag{5}$$

where:

k = a design constant, such as 0.875 or 0.9375.

The IIR filter has a memory and produces a non-zero output over an infinite time.

Relays are designed to track frequency within specified bounds (e.g., 40 to 65 Hz or 15 to 70 Hz) and slew rates (e.g., up to 9 Hz per second), while maintaining stated accuracies. Relays may default to nominal or boundary frequencies when the tracked system frequency goes out of bounds. In generator synchronizing applications, two measured voltages may be at significantly different frequencies. Special algorithms are introduced so that sampled data pairs are 90 degrees apart and off-nominal frequency filter coefficient errors are minimized.

In Fig. 13, when the utility source is lost, both the main breaker and the contactor feeding a mobile radar unit are opened. Three diesel generators are started at this point. Once two of the three generators are supplying sufficient voltage to the bus, the contactor closes to supply power to the radar unit. When the utility source returns, the generators are tripped, and 5 seconds later, the main breaker is closed, connecting the radar unit to the utility. Note that the radar contactor remains closed during the return switching process (shown in Fig. 13).

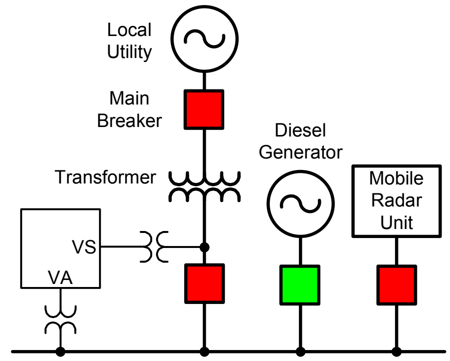

Fig. 13. Isolated system problem during utility resynchronization

An overvoltage element is enabled to trip in the relay shown at 115 percent of nominal voltage *with no time delay*. This element misoperates when the main breaker is closed to reconnect the radar unit to the utility. According to IEEE C37.102 and IEEE 1547, a short time delay should be included on this voltage element. In Fig. 14, note that the frequency measured before the main breaker close is significantly less than the nominal 60 Hz. Why does the relay frequency tracking algorithm think that the system frequency is 50 Hz?

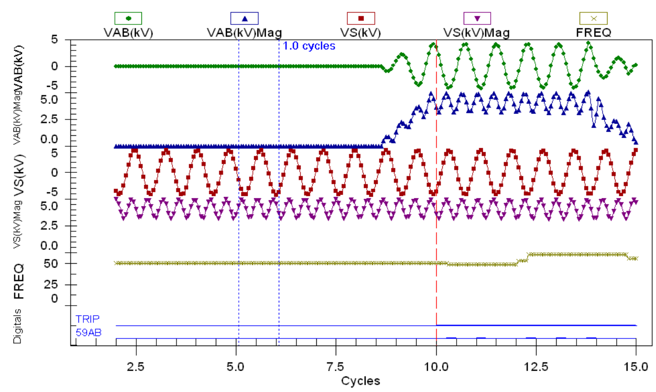

Fig. 14. Overvoltage element trip due to sampling frequency error

When the generators are shut down before reconnecting to the utility, the bus voltage takes some time to decay. During this time, the measured frequency decays to approximately 50 Hz. This relay tracks frequency on VA voltage until it becomes too low; then the relay switches to track I1. In this case, the contactor remains closed, preventing the relay from detecting a three-pole open condition. A simple solution is to open the radar contactor during the 5-second return transfer to the utility source. This allows the frequency tracking algorithm to reset to nominal, and the relay correctly samples and calculates the voltage magnitude when the main breaker is closed.

The relay samples 16 times per power system cycle based on the output of the frequency tracking algorithm. Because the frequency tracking algorithm output when the breaker is first closed is approximately 50 Hz, compared to the actual system frequency of 60 Hz, the relay uses the reduced frequency measurement and samples at a too-low rate. Fig. 14 shows that 16 samples cover more than one cycle of a waveform. Phasors use a present sample and a sample that is 0.25 cycles old. Because the sampling frequency does not match the system frequency, this produces an error in the VAB(kV)Mag shown in Fig. 14. Due to the error, the peak magnitude exceeds the overvoltage element and causes the trip.

Interestingly, one protection algorithm that works in spite of frequency tracking errors is differential protection. Fig. 15 shows a differential relay protecting a step-up transformer on an offshore oil platform. The variable frequency drive (VFD) may operate outside the frequency tracking range of the relay. Because the sampling frequency and the system frequency are different, the current magnitudes, including operate and restraint, will oscillate. However, the ratio of operate to restraint is steady and does not oscillate. Differential protection can be applied without concern for security; sensitivity is compromised at lower frequencies.

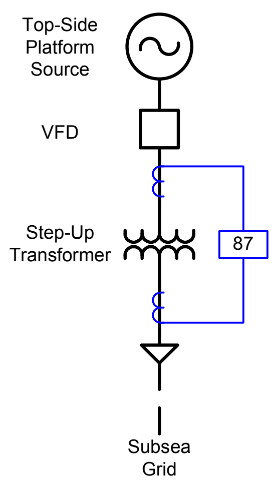

Fig. 15. Differential protection downstream of a VFD

III. How Do Frequency Excursions Affect Memory-Polarized Distance Elements?

How do frequency excursions affect the performance of protective relays, particularly for distance elements on transmission lines?

One popular method of implementing mho elements for line protection is to use a characteristic point mapping approach. The advantage of this method is that a reach, *m*, is calculated for all fault loops and is compared against the reach setting for all zones. Another advantage is that, provided the fault resistance is small, *m* equals a value close to the distance to the fault.

Six impedance loops are used by the distance elements corresponding to the three phase-to-ground loops (AG, BG, CG) and the three phase-to-phase fault loops (AB, BC, CA).

For each fault loop, an operating and polarizing quantity is chosen to develop a scalar product. The reach setting of the relay is compared to the scalar *m* for each mho loop (AB, BC, CA, AG, BG, CG), as described by this general equation:

$$m = \frac{\text{real}\left(Vr \bullet V_{pol}{}^{*}\right)}{\text{real}\left(ZL \bullet Ir \bullet V_{pol}{}^{*}\right)} \tag{6}$$

where:

ZL = replica line impedance.

m = per-unit reach in terms of replica line impedance.

I = measured relay current.

Vr = measured relay voltage.

V_{pol} = polarizing voltage.

The most popular choice for V_{pol} is positive-sequence voltage memory (V1mem). The advantages of V1 polarizing memory are many. First, it allows mho elements to achieve greater expansion, providing more fault resistance coverage. Second, it provides excellent stability for single-pole trip applications. Most importantly, it provides stable performance during zero-voltage fault conditions or faults on series-compensated lines [8] [9].

To achieve a polarizing *memory*, we use a portion of the healthy prefault V1 voltage and a portion of the present V1 voltage. The relative portion of each (prefault and present) determines a time constant. The more prefault voltage we use, the larger the time constant, and the longer the positive-sequence voltage persists.

Many designs use two time constants. A shorter time constant is typically in use during steady-state conditions and most faults. A longer time constant is enabled for close-in three-phase faults (e.g., for short lines or reverse bus faults) and series-compensated lines [10]. The longer memory allows phase distance elements to remain stable even if clearing times take longer than expected (e.g., breaker failure and Zone 2 timing) or for voltage inversions that are characteristic of series-compensated lines.

For example, if we say that the memory voltage is valid as long as it stays above 1 V secondary, we can calculate how long the distance elements are stable for a bolted three-phase fault using (7). In this case, if we switch the voltage from nominal (67 V) to zero and use a time constant (τ) of 31.9 cycles, the V1 memory stays above 1 V secondary for over 2 seconds. See Fig. 16. The voltage threshold and the time constant are design variables.

$$t := -\tau \bullet \ln\left(\frac{1}{67}\right) \qquad (7)$$

$$t = 134 \text{ cycles}$$

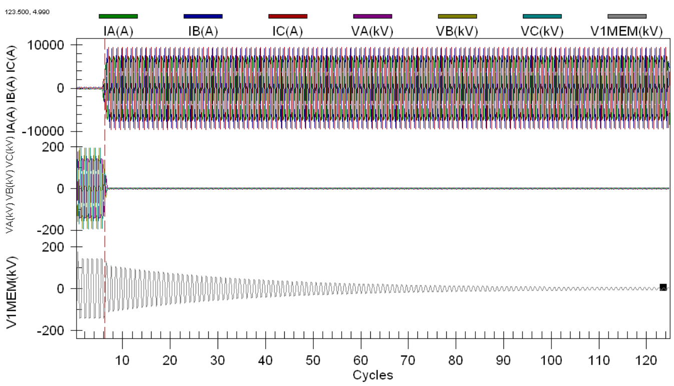

Fig. 16. V1 memory voltage persists above 1 V secondary for a bolted three-phase reverse fault

Although a mho element is inherently directional, it is customary to supplement the mho distance calculation with directional element supervision. For phase-to-phase mho elements, the directional element uses negative-sequence impedance (32Q) for unbalanced faults.

For three-phase faults, the denominator terms from (6), which we call DmAB, DmBC, DmCA, act as a directional element. If they are all positive values, the relay declares forward; if they are all negative values, the relay declares reverse.

Additional mho element supervision requires:

- Fault type selection (FIDS) to distinguish between phase-to-ground and phase-to-phase-to-ground faults.
- Load encroachment logic (ZLOAD) to distinguish between load and a three-phase fault.
- Measured current to exceed fault detector overcurrent (50AB) elements.

Based on these principles, Fig. 17 represents the base logic for the A-phase-to-B-phase faults mho element.

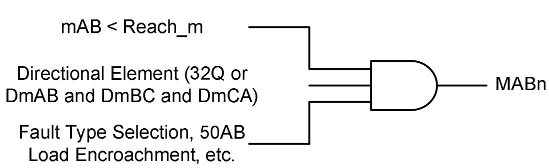

Fig. 17. Basic logic for A-phase-to-B-phase mho element

Now, consider the relationship between the power system frequency and polarizing memory. If the power system frequency changes rapidly and frequency tracking cannot keep up, we begin to see a slip between the actual system frequency and estimated frequency. The polarizing memory voltage develops a phase angle error with respect to the present voltage. For example, if there is a one-cycle difference between the actual to estimated frequency for 1 second, the angle of V1mem will be in error by 360 degrees.

Recall that the DmPP (DmAB, DmBC, DmCA) quantities form the directional element for three-phase fault conditions. Now consider a condition where frequency changes quickly under otherwise steady-state conditions. Even if we are using a short time constant, the difference in the actual and estimated frequency can cause error in the V1 memory angle. If the angle error is great enough, it can cause the signs of the DmPP terms to change (positive to negative or negative to positive) and the mho element could produce an undesired operation.

So the benefits of V1 memory polarization, when it remembers the healthy prefault data, are tempered by the issues caused when the frequency is not tracking properly (i.e., prefault voltage is not healthy).

The following example demonstrates how a system frequency oscillation can result in mho element operation. Fig. 18 shows a one-line diagram of a system with a line protected by a distance relay. A three-phase distribution fault occurs and is eventually cleared.

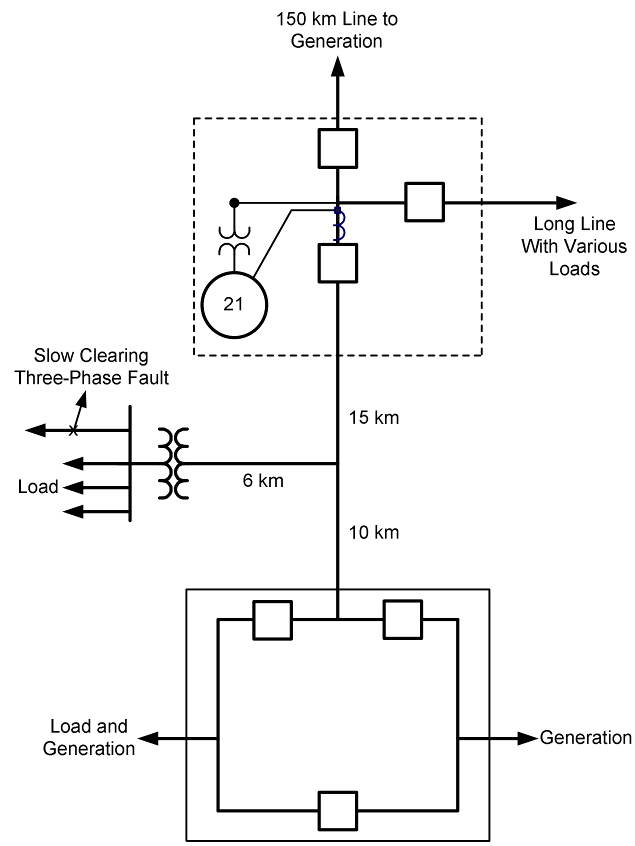

Fig. 18. One-line diagram of isolated system

After the fault clears, the local generation compensates to maintain system voltage magnitude and frequency. However, because this is an isolated system far from generation sources, the frequency oscillates as a new equilibrium is reached between load and generation.

Eventually, the mho element on the protected line trips. The result is a line outage. A screen capture of the event is shown in Fig. 19.

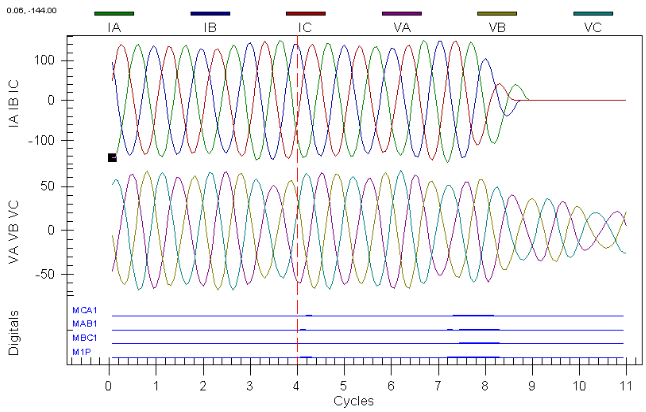

Fig. 19. Screen capture of line trip during system oscillation

IV. What Practical Advice or Solutions Can We Implement?

A. Use Load Encroachment Characteristic When Possible

In the example in Fig. 19, the maximum (Zone 2, 3, etc.) mho element reach is about 1 ohm secondary. The maximum load is on the order of 30 MW (21 ohms secondary). Even extreme loading will never approach the mho element reach.

Recall that we can apply a load encroachment (ZLOAD) element to supervise the mho element operation. This element does not depend on memory voltage. Instead, it measures the positive-sequence impedance (Z1). If there is enough margin between the maximum mho reach and the load region, the load encroachment element can be set to completely encircle the mho elements. Thus, any Z1 measured outside the ZLOAD circle is considered load, and we block the mho element.

Fig. 20 shows a graphical representation of the positive-sequence impedance (Z1) plane.

To test this, we replayed the original event with ZLOAD enabled as described. We used a ZLOAD setting of 5 ohms, far greater than the maximum reach and far inside the maximum load. As expected, the measured Z1 oscillates while the frequency is moving, but always stays well outside the ZLOAD characteristic (Fig. 21). Supervising the mho element with load encroachment adds security during the frequency excursion.

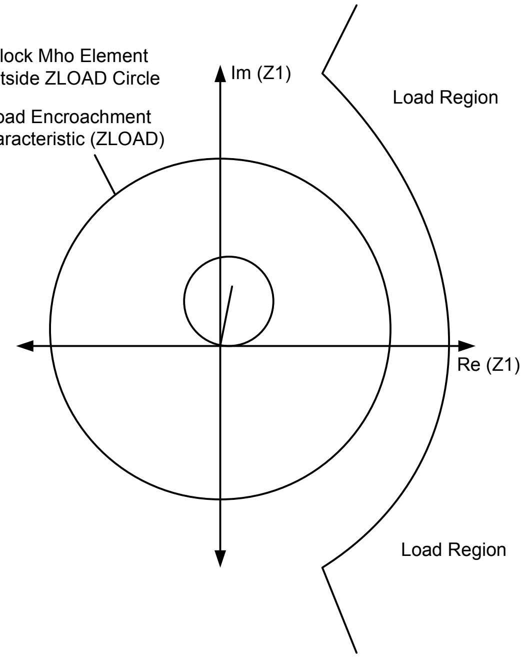

Fig. 20. Plot of mho and load encroachment characteristic on positive-sequence impedance plane

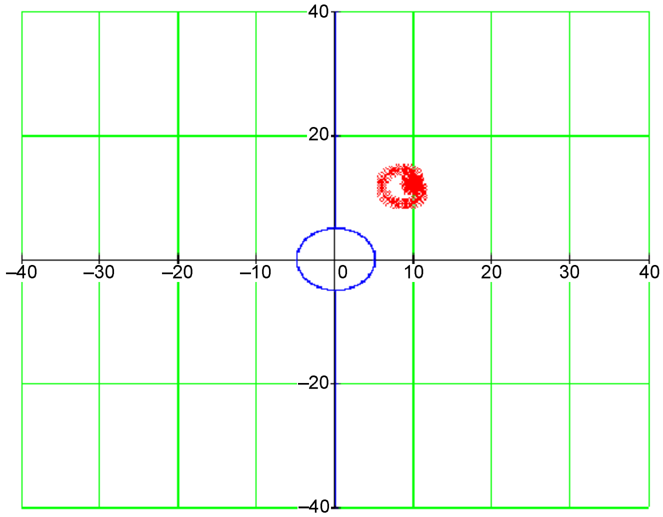

Fig. 21. Plot of load encroachment characteristic (blue) and measured Z1 (red) on positive-sequence impedance plane

B. Extend Reclosing Times to Allow Memory to Expire

In the following event, a mho element operates on a reclose. Fig. 22 shows a single-phase-to-ground fault for which the relay trips as expected. However, note at the end of the graph, there is still about 19 kV of V1 memory voltage present on this 230 kV line.

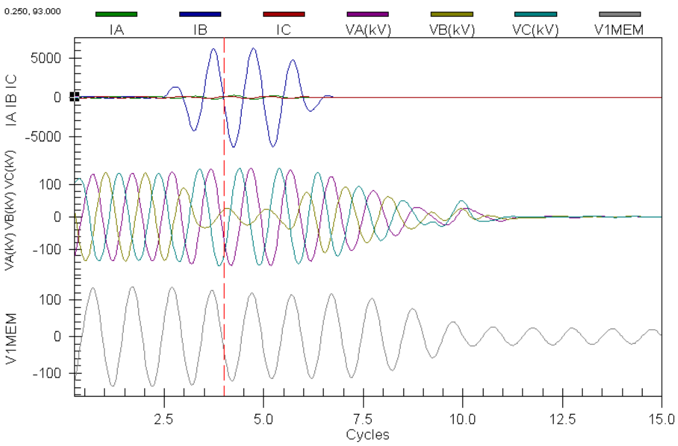

Fig. 22. Initial fault clears but shows V1 memory voltage still present

The reclose time is about 30 cycles. In Fig. 23, we can see the mho elements operate on the reclose. There are two contributing factors. One is some lingering voltage from the CVT ring down, as shown in Fig. 22.

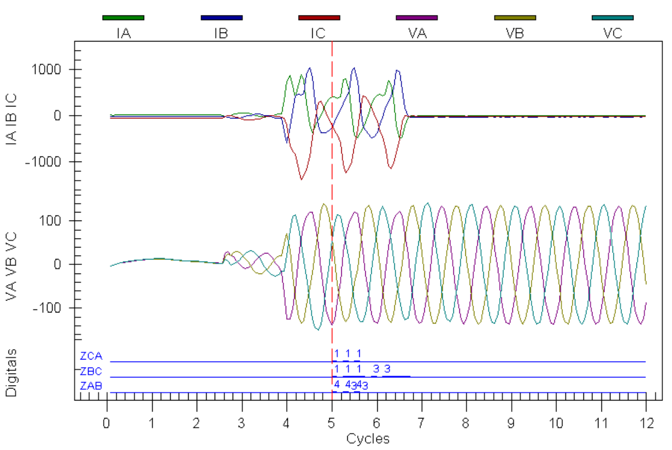

Fig. 23. Unfiltered event report shows mho element operation with CVT ring-down voltage

The second factor is that the V1 memory voltage did not completely decay before the reclose, as seen in Fig. 24. As a result, the mho elements are enabled and misoperate upon reclose.

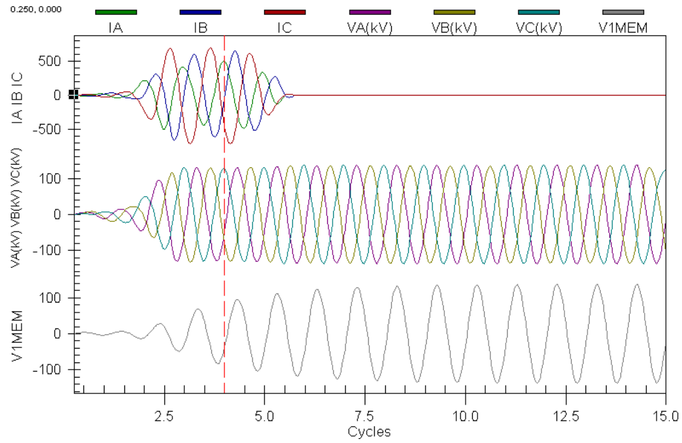

Fig. 24. Filtered event report shows V1 memory voltage still present prior to reclose

A simple solution is to extend the reclosing interval to a time greater than the polarizing memory decay. This time depends on the relay design, usually between 1 to 2 seconds.

Fig. 25 shows a separate but similar event. A 161 kV line experiences a temporary single-line-to-ground fault. A reclose after 30 cycles is attempted, and the relay is tripped by the mho element during the reclose.

There are three contributing factors in this case. First, the CVTs are found to have multiple ground connections, which produce erroneous voltage magnitude and angles during the fault. Second, the line-side CVTs have a long transient response, which continues to fuel the V1 memory voltage and corrupt the V1 memory magnitude and angle. Third, during the reclose, inrush current from a tapped transformer load is present and greater than fault detectors.

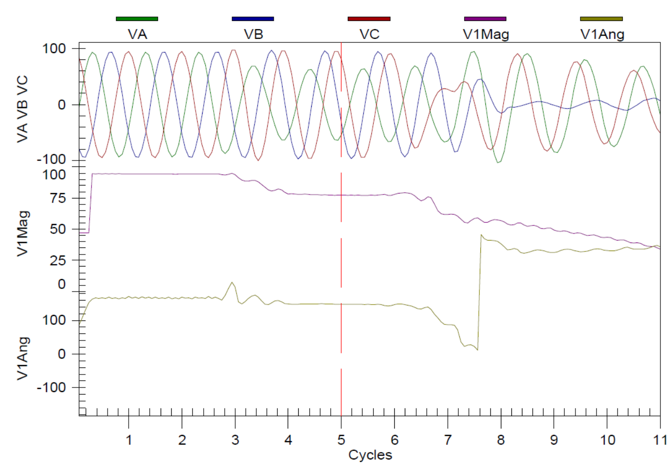

Fig. 25. Similar event report shows V1 memory voltage due to CVT transient, load, and wiring error

C. Reduce or Eliminate Time Constant of Voltage Memory to Make Element More Dependent on Present Voltage

The system shown in Fig. 26 experienced an extreme condition that resulted in another mho element operation. In this case, all three source lines connected to this 138 kV bus are lost due to several unexpected system events. With the industrial facility, the only remaining source, the small generator, tries to pick up all of the remaining loads on the bus.

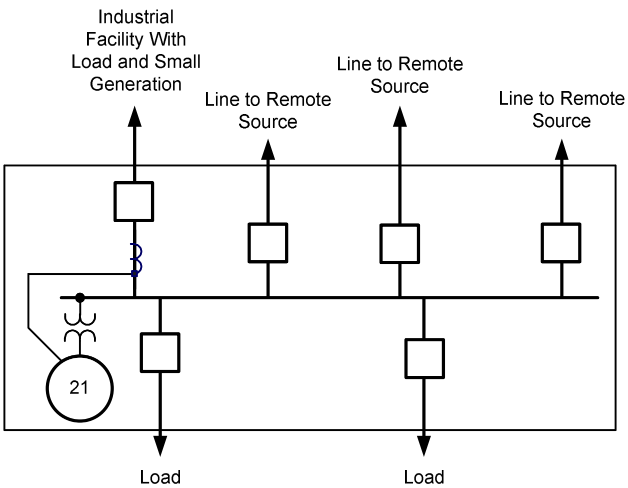

Fig. 26. System one-line diagram

Fig. 27 shows the event data from the distance relay. During the first part of the event, the frequency is about 47 Hz and drops to about 42 Hz. When one of the source lines recloses, the frequency jumps up to about 62.7 Hz. The frequency excursion ultimately results in a trip of the relay supplying the industrial facility. The relay design calls for the frequency to track down to 40 Hz, but the system frequency changes too rapidly for the relay to track.

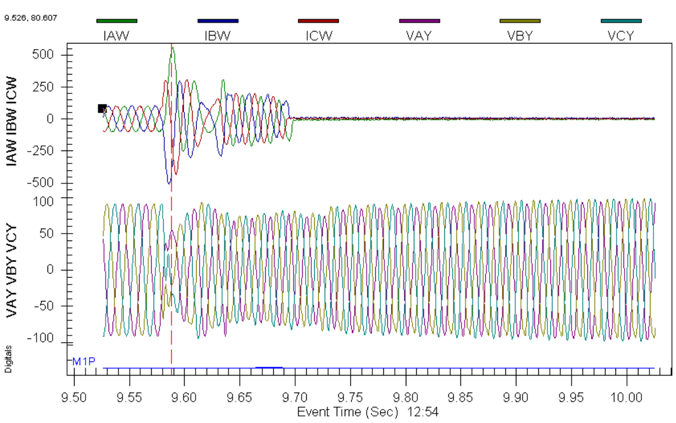

Fig. 27. Voltages and currents during frequency excursion

Fig. 28 shows the *m* calculation of the three phase-to-phase mho elements as the event progresses. When the *m* calculation crosses below the relay setting threshold, the relay trips.

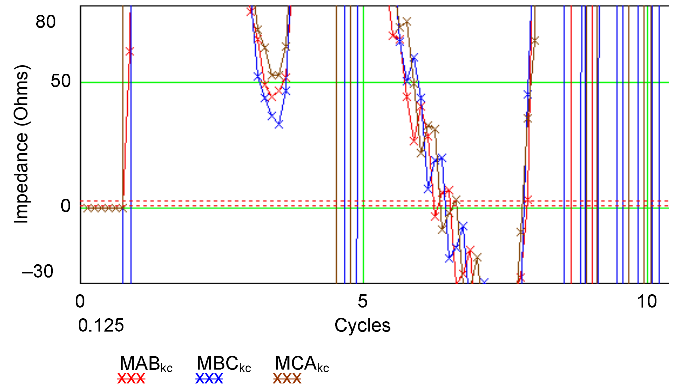

Fig. 28. Mho element *m* calculations

Fig. 29 shows how the V1 memory voltage departs from the V1 measured voltage due to the error in the frequency tracking.

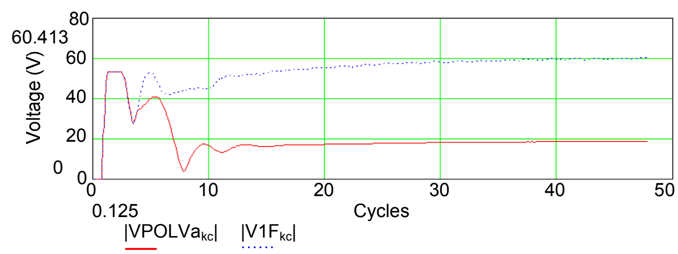

Fig. 29. V1 memory and V1 measured voltages during the event

Suppose we adjust the time constant (τ) to a value approaching zero. In other words, what if we remove memory from the *m* calculation completely? In this case, the V1 memory would essentially track along with the measured voltage, as seen in Fig. 30.

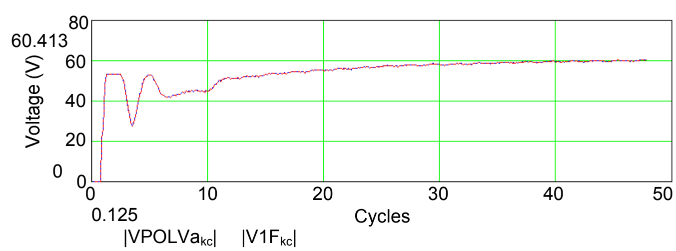

Fig. 30. V1 memory voltage is identical to V1 measured with $\tau = 0$

The result, if the relay uses a time constant approaching zero, is that the relay would not have operated. In Fig. 31, with $\tau = 0$, the mho element *m* calculation stays above the relay reach setting and the relay is secure.

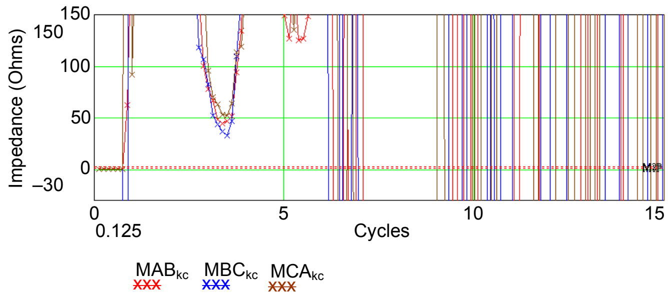

Fig. 31. Mho element *m* calculation if $V1_{pol}$ with $\tau = 0$

V. Conclusions

In this paper, several system events have been shown in which a frequency excursion resulted in an undesired operation. However, we should note that the number of actual failures due to this phenomenon is quite small. Based on actual field data, the failure rate is approximately 0.000033, or in other words, the likelihood of a failure is less than 1 in 30,000 per year. But undesired operations, however infrequent, are always a concern for protection engineers, and this is no different.

Phasor magnitude and angle accuracy is dependent on proper frequency tracking. Errors in frequency tracking, therefore, can cause incorrect magnitude and phase measurements and improper relay operation.

Lessons learned from the event data in this technical paper include the following:

- Recognize ripple or oscillation in filtered phasor magnitudes in event data as indication of frequency tracking errors.
- Consult with manufacturers to understand how different relay makes and models track frequency.
- Understand how key settings, such as phase rotation, nominal voltage, and alternate frequency source selection logic, affect relay frequency tracking performance.
- For relays with VA frequency tracking, consider forcing VA to zero during open-pole conditions with a 52A contact.
- For relays that switch from VA to I1 for frequency tracking, consider opening load breakers during transfer operations to reset frequency tracking.
- Ensure that VFD or similar applications do not force relays outside specified frequency operating bounds (or consider elements such as differential protection that are more secure at off-nominal frequencies).
- Take care to ensure that voltage transformer connections to relays are properly wired and grounded.
- Set reclosing intervals longer in applications with line-side CVTs and significant ring-down transient response.
- Set fault detectors above maximum load and transformer inrush.
- Use load encroachment to supervise V1 memory-polarized mho elements to add security during off-nominal operation.
- Reduce or eliminate the time constant of voltage memory to make mho elements more dependent on present voltage for steady-state and most fault conditions (use longer time constant for low-voltage faults).

VI. Acknowledgment

The authors express their sincere appreciation to several engineers at Schweitzer Engineering Laboratories, Inc. for sharing their expertise. Derrick Haas performed fast motor bus transfer testing. Carl Mattoon and Normann Fischer educated us on frequency tracking algorithms. Jason Young shared real-world event data. Michael Thompson researched differential protection at off-nominal frequency. This paper would not be possible without these valuable contributions.

VII. References

[1] J. Nilsson, *Electric Circuits*, 2nd ed. Addison-Wesley Publishing Company, Reading, MA, 1986.

[2] M. Grady, Texas Synchrophasor Network Information. Available: http://users.ece.utexas.edu/~grady/.

[3] IEEE Guide for Abnormal Frequency Protection for Power Generating Plants, IEEE C37.106.

[4] H. J. Altuve Ferrer and E. O. Schweitzer, III (eds.), *Modern Solutions for Protection, Control, and Monitoring of Electric Power Systems*. Schweitzer Engineering Laboratories, Inc., Pullman, WA, 2010.

[5] ERCOT Daily Grid Operations Reports. Available: http://www.ercot.com/gridinfo/congestion/operations/.

[6] ERCOT Current Operating Guide. Available: http://www.ercot.com/mktrules/guides/operating/current.

[7] U.S.-Canada Power System Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004. Available: https://reports.energy.gov/BlackoutFinal-Web.pdf.

[8] E. O. Schweitzer, III and J. Roberts, "Distance Relay Element Design," proceedings of the 46th Annual Conference for Protective Relay Engineers, College Station, TX, April 1993.

[9] H. J. Altuve, J. B. Mooney, and G. E. Alexander, "Advances in Series-Compensated Line Protection," proceedings of the 35th Annual Western Protective Relay Conference, Spokane, WA, October 2008.

[10] J. B. Roberts and D. Hou, "Adaptive Polarizing Memory Voltage Time Constant," U.S. Patent 5,790,418, August 1998.

VIII. Biographies

David Costello graduated from Texas A&M University in 1991 with a BSEE. He worked as a system protection engineer at Central Power and Light and Central and Southwest Services in Texas and Oklahoma and served on the System Protection Task Force for ERCOT. In 1996, David joined Schweitzer Engineering Laboratories, Inc., where he has served as a field application engineer and regional service manager. He presently holds the title of senior application engineer and works in Boerne, Texas. He is a senior member of IEEE and a member of the planning committee for the Conference for Protective Relay Engineers at Texas A&M University. David was a recipient of the 2008 Walter A. Elmore Best Paper Award from the Georgia Institute of Technology Protective Relaying Conference and a contributing author to the reference book *Modern Solutions for the Protection, Control, and Monitoring of Electric Power Systems*.

Karl Zimmerman is a senior power engineer with Schweitzer Engineering Laboratories, Inc. in Fairview Heights, Illinois. His work includes providing application and product support and technical training for protective relay users. He is an active member of the IEEE Power System Relaying Committee and chairman of the Task Force on Distance Element Performance with Non-Sinusoidal Inputs. Karl received his BSEE degree at the University of Illinois at Urbana-Champaign and has over 20 years of experience in the area of system protection. He is a past speaker at many technical conferences and has authored over 20 papers and application guides on protective relaying.

Previously presented at the 2011 Texas A&M
Conference for Protective Relay Engineers.

20110216 • TP6485-01