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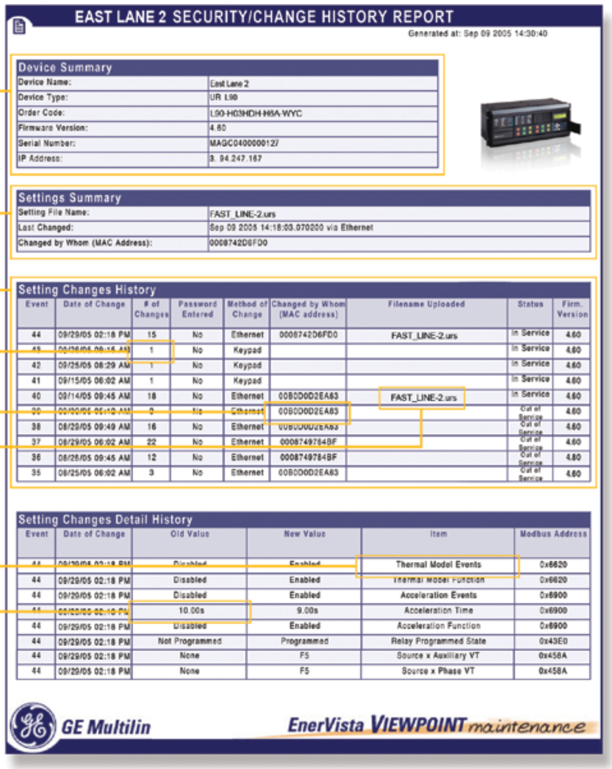
- Date of last 10 times a setting was changed
- Number of settings changed each time
- Who changed these settings
- Name of the Settings File sent to the relay
- Which settings were changed
- The Settings' previous and current values



EAST LANE 2 SECURITY/CHANGE HISTORY REPORT

Generated at: Sep 09 2005 14:30:40

Device Summary	
Device Name:	East Lane 2
Device Type:	UR L90
Order Code:	L90-H03HDH-H6A-WYC
Firmware Version:	4.60
Serial Number:	MAGC0400000127
IP Address:	3. 94.247.167

Settings Summary	
Setting File Name:	FAST_LINE-2.urs
Last Changed:	Sep 09 2005 14:18:03.070200 via Ethernet
Changed by Whom (MAC Address):	0008742D6FD0

Setting Changes History

Event	Date of Change	# of Changes	Password Entered	Method of Change	Changed by Whom (MAC address)	Filename Uploaded	Status	Firm. Version
44	09/29/05 02:18 PM	15	No	Ethernet	0008742D6FD0	FAST_LINE-2.urs	In Service	4.60
43	[illegible]	1	No	Keypad			In Service	4.60
42	09/25/05 08:29 AM	1	No	Keypad			In Service	4.60
41	09/15/05 06:02 AM	1	No	Keypad			In Service	4.60
40	09/14/05 09:45 AM	18	No	Ethernet	00B0D0D2EA83	FAST_LINE-2.urs	In Service	4.60
[illegible]	[illegible]	[illegible]	No	Ethernet	00B0D0D2EA83		Out of Service	4.60
38	08/29/05 09:49 AM	16	No	Ethernet	[illegible]		Out of Service	4.60
37	08/29/05 06:02 AM	22	No	Ethernet	0008749784BF		Out of Service	4.60
36	08/26/05 09:45 AM	12	No	Ethernet	0008749784BF		Out of Service	4.80
35	08/25/05 06:02 AM	3	No	Ethernet	00B0D0D2EA83		Out of Service	4.60

Setting Changes Detail History

Event	Date of Change	Old Value	New Value	Item	Modbus Address
[illegible]	[illegible]	[illegible]	[illegible]	Thermal Model Events	0x6620
44	09/29/05 02:18 PM	Disabled	Enabled	[illegible]	0x6620
44	09/29/05 02:18 PM	Disabled	Enabled	Acceleration Events	0x6900
[illegible]	[illegible]	10.00s	9.00s	Acceleration Time	0x6900
44	09/29/05 02:18 PM	[illegible]	Enabled	Acceleration Function	0x6900
44	09/29/05 02:18 PM	Not Programmed	Programmed	Relay Programmed State	0x43E0
44	09/29/05 02:18 PM	None	F5	Source x Auxiliary VT	0x458A
44	09/29/05 02:18 PM	None	F5	Source x Phase VT	0x458A

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CT Saturation in Industrial Applications

Analysis and Application Guidelines

Bogdan Kasztenny, Jeff Mazereeuw, Kent Jones

1. Introduction

It is possible that relatively low-ratio CTs are applied for protective relaying of small loads fed from switchgear and motor controllers of relatively high short-circuit capacity. Assume the worst-case scenario of 64kA available fault current from bus feeding a small motor load of normal current below 50A. In theory, CTs rated as lows as 50:5 and relay class C10 may be applied for protection purposes.

Realizing that 64kA of fault current is 1080 times the rated current of the 50:5 CT, the magnitude of the problem is evident. Protection class CTs are designed to work in the linear range, with minimal errors and minimal waveform distortion, only up to 20 times the rated nominal current with the burden as defined by the relay class (saturation voltage) of the CT per IEEE Std. C57.13.

Well-established and relatively accurate equations are available for calculation of the actual maximum primary current for saturation-free operation under any specific burden, any specific X/R ratio, and any specific residual flux in the CTs. This engineering practice is of little help here: A CT fed with a primary current hundreds of times its rated current will saturate severely - only relatively short duration peaks of limited current will be observed from the secondary of the CT. These peaks can be as low as 5-10% of the ratio current, and will last a small fraction of the half-cycle, down to 1-2ms in extreme cases. As a result only a very small portion of the actual ratio current is presented to protective relays fed from such severely saturated CTs. In terms of the true RMS value, the secondary current may be as low as 1-2% of the expected RMS secondary current.

On the surface it may seem that a severe problem takes place here – the fault current is so high that it virtually stops the CT from passing the signal to the relay. The relay does not see enough proportional secondary current during severe faults in order to operate its short circuit protection. The upstream relay, using CTs of a much higher ratio, measures the fault current more accurately and trips. Zone selectivity is lost because the poor low-ratio CT was “blinded” to the fault.

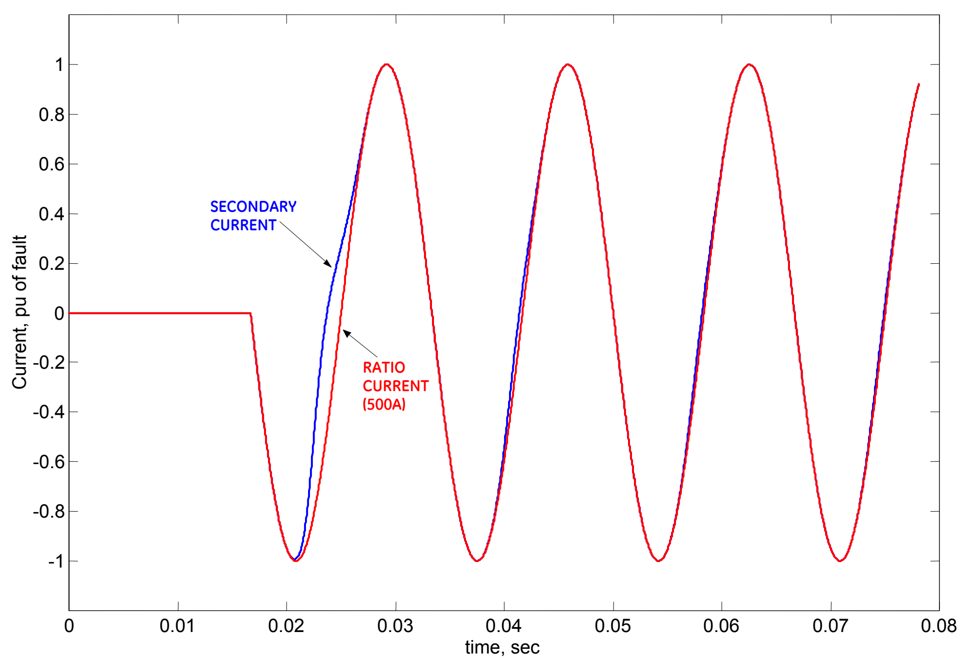
It is justified to assume that vast majority of industrial applications are not supported by computer simulation studies (EMTP) of saturated CTs, or any lengthy and sophisticated CT analysis. At the same time there is a population of relays installed on high capacity buses and fed from low ratio CTs. An obvious question arises: why does the above problem not demonstrate itself in the field?

In this paper we will analyze the problem in detail and explain its underlying mechanics. Several GE Multilin relays are analyzed in terms of their response to heavily saturated waveforms. A formal, compact and easy to grasp method is shown to present complex relations between the CT response and the response of any given relay. Based on this graphical method one can quickly evaluate the problem (do I have a problem when using relay X, with CT Y, under fault capacity Z, and overcurrent pickup setting Q?), and clearly see alternative solutions if a problem truly exists (i.e. definition of a method to match relays with CTs).

This paper illustrates that many unknowns in analysis do not have significant impact on the outcome. Reasonable conclusions will be evident from the results, even though broad assumptions are made in the model.

This exploratory analysis shows that severely saturated

Fig.1.
50:5, C10, CT with a burden of 0.2ohms under fault current of 500A (symmetrical).



CTs only slightly reduce short circuit tripping capabilities of GE Multilin's relays. Given the typically applied settings, there is no danger of a failure to trip from intantenous overcurrent functions even in extreme cases of very high short-circuit currents and low-ratio CTs.

2. Severe Saturation of Low-Ratio CTs

Well-established engineering practice exists for CT selection to ensure saturation free-operation of protection CTs at a given short circuit level, CT burden, X/R ratio and assumed residual flux. In the context of this paper, it is assumed that this engineering technique is not applied, and severe saturation will occur for short circuits within the protected zone (motor, feeder, cable or bus).

Analytical analysis of a saturated CT is not practical. Only "time to saturation" may be approximated with relative ease, and is used in some protection applications. More detailed analytical analysis is not in the realm of practical engineering.

Computer simulations are the only efficient way to extract the required information on secondary signals. These are burdensome for everyday engineering in the industrial domain. This paper uses computer simulation to derive simple and practical analysis and engineering charts to address the problem.

Figures 1 and 2 present plots of the proportional secondary CT current, and the simulated secondary current for a 50:5, C10, CT with a 0.2ohm resistive burden under the fault current of 10 times nominal current (without and with full dc offset, respectively). This poor performance CT with this particular burden saturates slightly under 500A ac current (Figure 1), and accordingly more when full dc offset is present in the primary current (Figure 2). This document uses a digital model of a CT. More information on the model and its validation can be found in Section 7.

Figures 3 and 4 present the performance of the same CT under the fault current of 200 times the nominal, i.e. 10kA. Now, the saturation is much more severe.

This paper focuses on extreme cases of CT saturation, with primary current as high as 1000 times the rated value. Figures 5a through 6b present a series of secondary currents superimposed on the ratio current. The primary current ranges from 200 to 1500 times the CT rating (10kA to 75kA in this case). All traces are rescaled to the peak of the ratio current for easy visualization (in this way all currents have the same graphical scale). Figure 5 is for symmetrical currents, and Figure 6 for the fully offset currents.

These figures illustrate severity of the problem. The secondary current is as low as 5-8% of the expected ratio current, and exhibits spikes shorter than 1ms when the fault current is as high as 75kA. Please note that this 50:5, C10, CT has a burden of 0.2ohms, virtually making it into an IEEE C57.13 "C5 relay class" equivalent.

It is important to observe that the secondary current, despite being extremely low compared with the fault current, is still very large compared with the CT and relay ratings:

For example, consider a fully offset 75kA current and a 50:5, C10, CT of Figure 6b. The peak value of the secondary current is only about 5% of the peak value of the fault current, but this translates to 0.05*75kA* $\sqrt{2}$ / (50:5) = 530A peak secondary, or 530A peak/($\sqrt{2}$ *5A) = 75 times rated value of the relay. This is a substantial current considering a typical conversion range of a microprocessor-based relay is 20-50 times the rated current. Figure 7 shows the relation between the peak value of the secondary current, and peak value of the ratio current for the simulated CT (10kA-75kA range).

Consider however, that it is the short duration of the peaks of the secondary current, not the low magnitude of those peaks that is important from the point of view of the signal strength delivered to the relay.

3. Microprocessor-Based Relays and Saturated Current Waveforms

As explained and illustrated in the previous section, low-ratio CTs pass proportionally less and less signal energy to the relay when the primary current increases dramatically. In an extreme case of the fault current being 1000 times the CT rating, only a small percent of this current, in the form of short spikes, would be delivered to the relay. This section explains and illustrates how a typical microprocessor-based relay responds to such waveforms. Response of Instantaneous Overcurrent functions is of primary interest.

With reference to Figure 8 a typical relay incorporates input current transformers (galvanic isolation), analog filters (anti-aliasing), A/D converter, magnitude estimator possibly with digital pre-filtering, and an Instantaneous Over-Current (IOC) comparator.

3.1. Impact of Relay Current Transformers

In general, the relay input CTs may saturate adding to the complexity of the analysis, and to the scale of the problem. However, saturation of relay input CTs may be neglected for the following reasons:

The secondary current is substantially reduced under severe saturation of main CTs. Moreover, saturation of the main CT makes the secondary current symmetrical eliminating the danger of exposing the relay input CT to decaying dc components. And thirdly, the secondary current has a form of short lasting spikes. This limits the flux in the cores of the relay inputs CTs.

For example, consider the case of Figure 5. Under say 75kA of symmetrical fault current the secondary current is approximately a series of triangular peaks of about 0.08*75kA* $\sqrt{2}$ / (50:5) = 848A secondary, lasting approximately 0.5-1ms. Assuming 1ms duration of these spikes, the true RMS of this secondary signal is only 120A, or 24 times the 5A rated of the relay input.

In reality, the relay input CT would have some impact on the response of the relay. Frequency response, i.e. ability to reproduce the short lasting input signal, may play a role.

Fig.2.
50:5, C10, CT with a burden of 0.2ohms under fault current of 500A (fully offset).

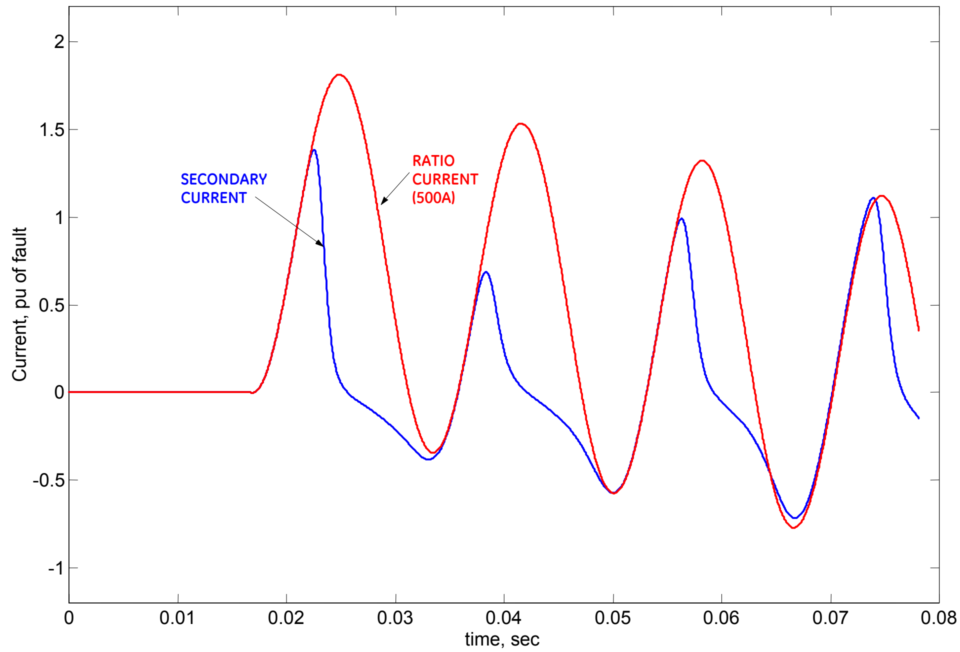


Fig.3.
50:5, C10, CT with a burden of 0.2ohms under fault current of 10kA (symmetrical).

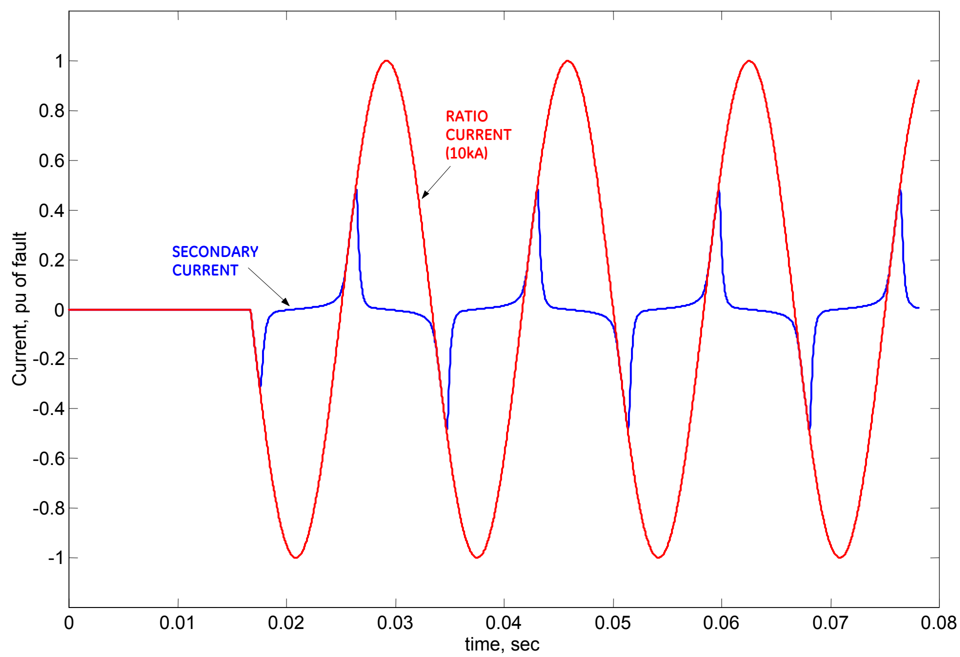


Fig.4.
50:5, C10, CT with a burden of 0.2ohms under fault current of 10kA (fully offset).

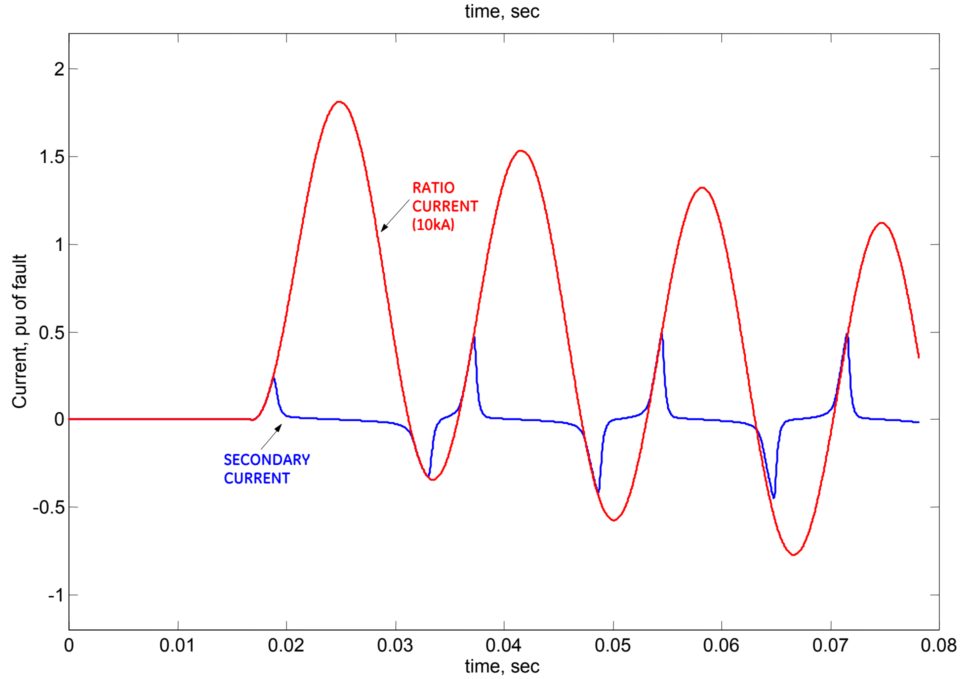


Fig.5a.
50:5, C10, CT with a burden of 0.2ohms under fault current up to75kA (symmetrical).

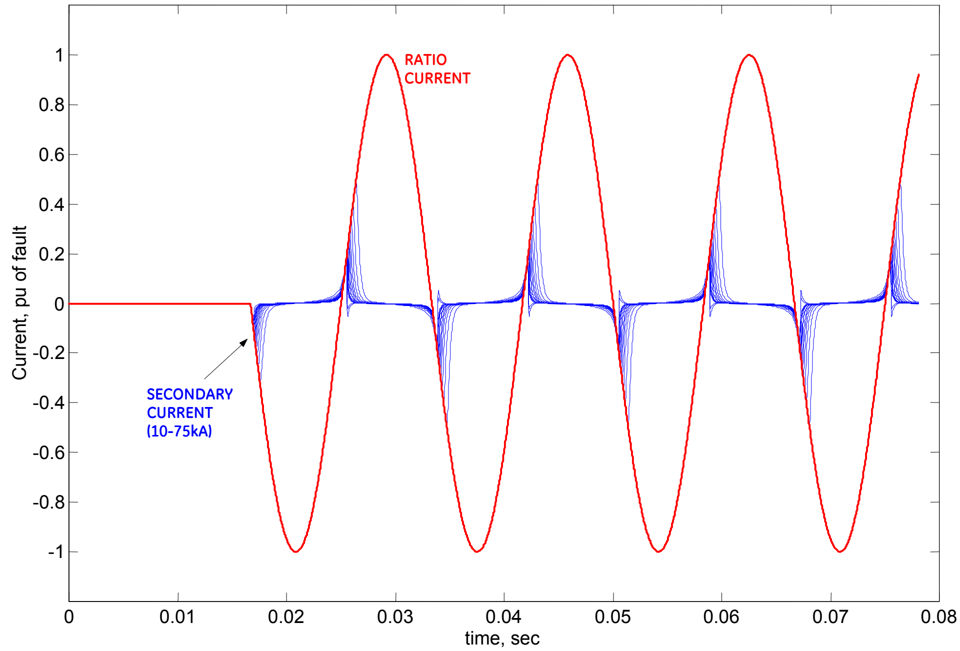


Fig.5b.
50:5, C10, CT with a burden of 0.2ohms under fault current up to75kA (symmetrical).

First half-cycle of the secondary current.

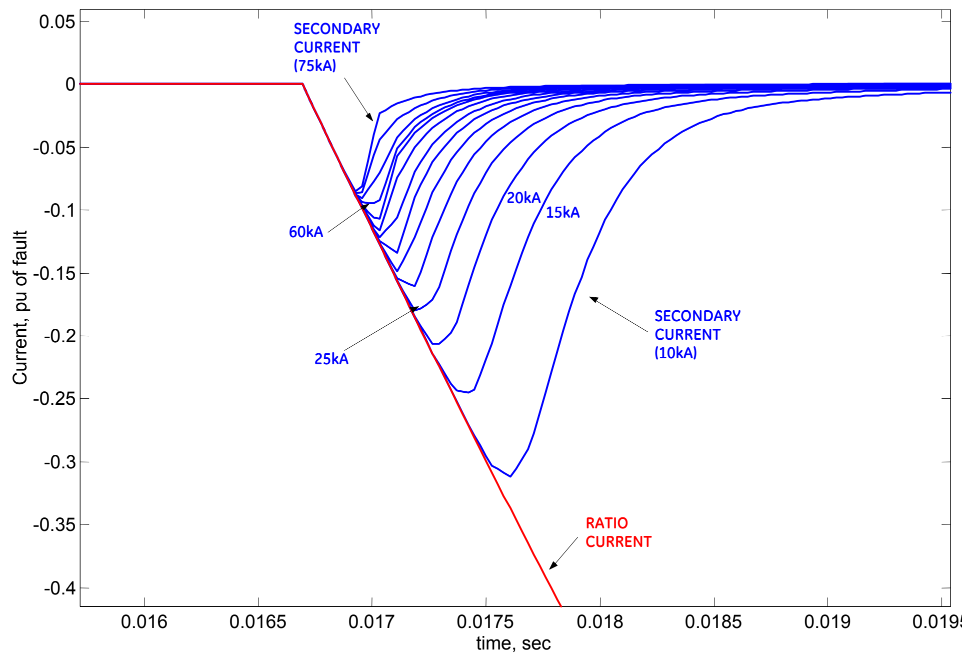


Fig.6a.
50:5, C10, CT with a burden of 0.2ohms under fault current up to75kA (fully offset).

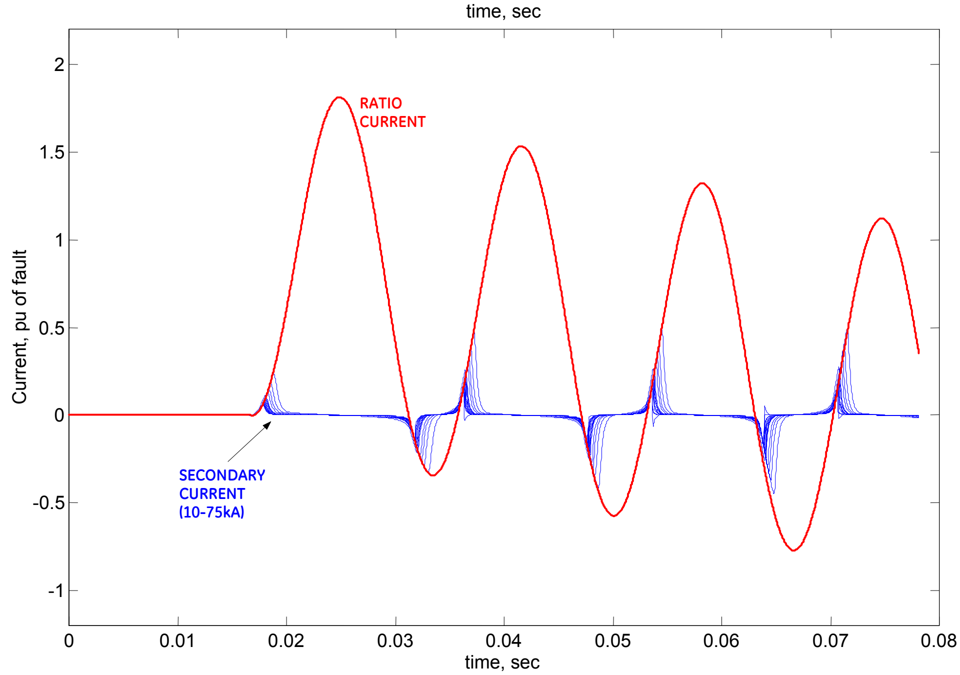


Fig.6b.
50:5, C10, CT with a burden of 0.2ohms under fault current up to75kA (fully offset).

First half-cycle of the secondary current.

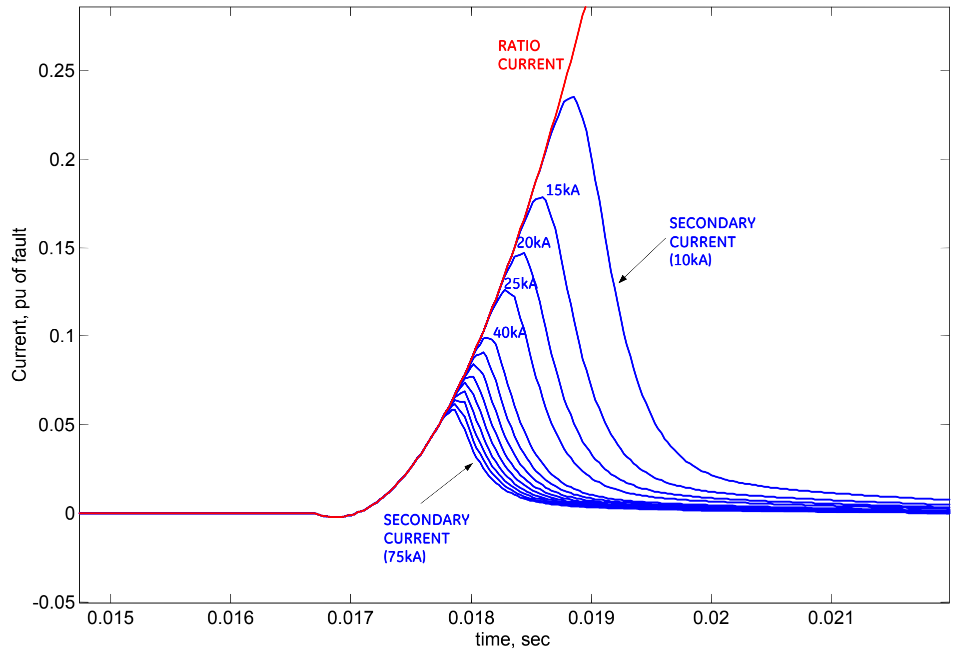


Fig.7a.
50:5, C10, CT with a burden of 0.2ohms: relation between the peak secondary current and peak fault current (symmetrical waveform).

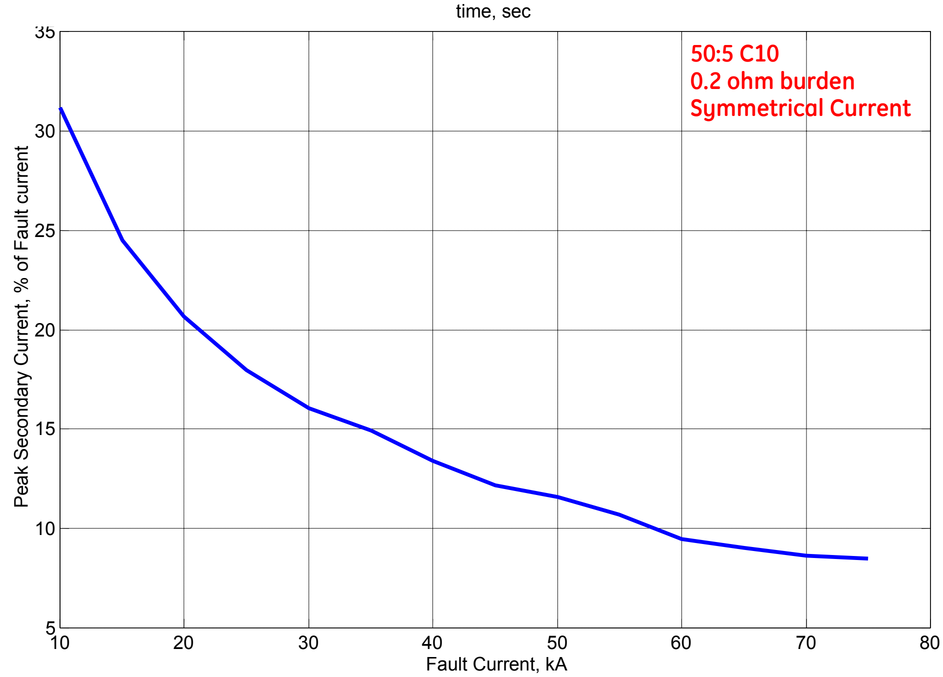
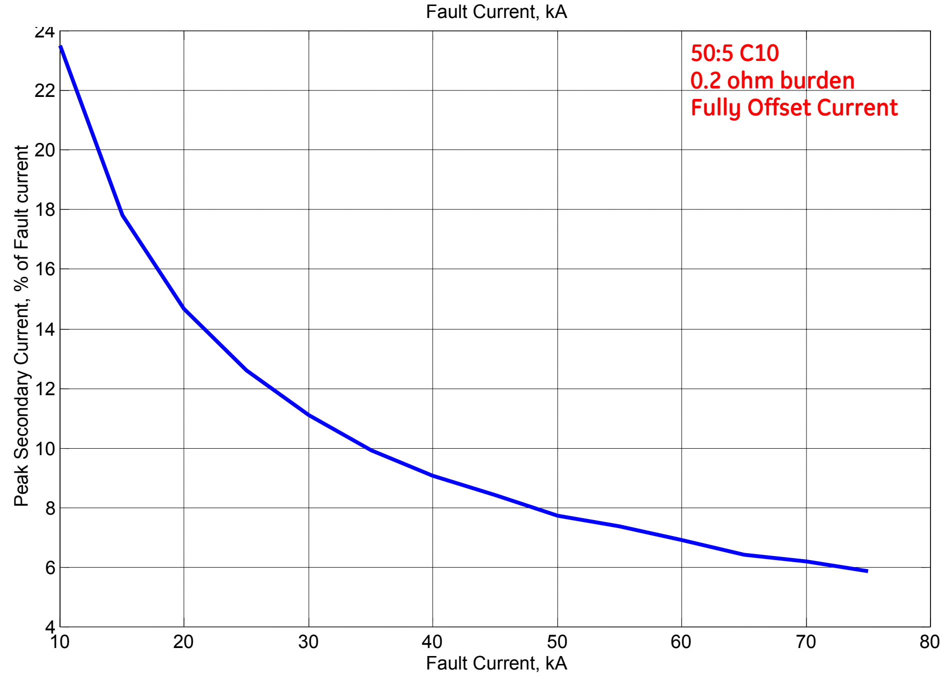


Fig.7b.
50:5, C10, CT with a burden of 0.2ohms: relation between the peak secondary current and peak fault current (fully offset waveform).



The theoretical analysis of this paper neglects the impact of relay input CTs it is believed to be small. This is confirmed through testing of actual relay hardware.

Given the short duration of the signal pulses produced by a heavily saturated CT, location of A/D samples on the waveform plays an important role. Consider Figures 12 and 13. In Figure 12 the samples lined up in a way that 3 samples in each cycle "caught" the peaks of the signal. In Figure 13 the samples lined up in a way that only 2 samples in each cycle aligned with the peaks. This will result in different values of the operating signal for the IOC function. In the analysis, the worst-case must be considered, and in this context, Figure 13 presents the worse condition.

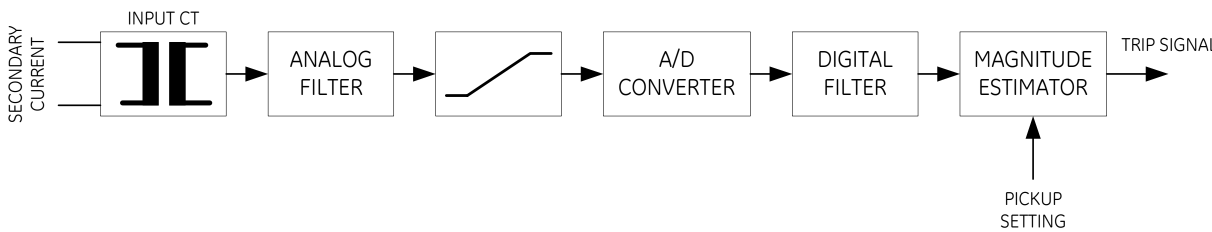


Fig.8. Signal processing chain of a typical relay.

3.2. Impact of the Analog Filter

Analog filters are implemented in order to prevent aliasing of higher frequencies on the fundamental frequency signal. Typically, a second order filter is used with a cut-off frequency of about 1/3rd of the sampling rate.

Analog filters have a positive impact on the response of the relay to heavily saturated current waveforms. Due to its intended low-pass filtering response, the analog filter reduces the peak values of its input signal and lengthens the duration of such spikes. In a way, the analog filters smoothes out the waveform by shaving its peaks and moving the associated signal energy into the area of lower magnitude. This phenomenon is illustrated in Figure 9. Given the fact that the peak magnitude of spikes is well above the conversion level of the relay, and as such it is not used by the relay when deriving the operating quantity, the operation of shifting some signal energy from the peaks into the low magnitude area would increase the operating signal, and improve the overall response of the relay.

Figure 9 assumes a linear analog filter, i.e. a filter that would not saturate despite of the high magnitude of its input. Most filters, however, are designed using active components (operational amplifiers) and will saturate on waveforms such as the one of Figure 9. Figure 10 shows response of a simplified model of such filter (clamping of the input signal to a linear filter). As seen in the figure, the signal is reduced even more. What is important, the analog filter shifts some portion of the signal energy into the low magnitude region when it is measured and utilized by the relay.

3.3. Impact of the A/D Converter

The impact of the A/D converter is twofold. First, any converter has a limited conversion range where signals above a certain level are clamped. This is similar to the response of the analog filter in front of the A/D converter (saturation of the amplifiers). The conversion range of today's relays is typically in the 10-50 span. For example, the GE 469 Motor Management Relay clamps the inputs at $28.3 * \sqrt{2} * 5A = 200A$ secondary peak, assuming the 5A rated current.

Figure 11 illustrates the impact of the A/D clamping on the signal processed by a given relay. The second aspect related to the A/D conversion is a limited sampling rate. Today's relays sample at rates varying from 8 to 128 samples per cycle. Industrial relays tend to sample at 8-16 times per cycle.

It is also intuitively obvious that higher sampling rates give better chance to "integrate" the short lasting signal pulses and yield a higher operating signal, and thus better relay performance. This is illustrated in Figure 14 where the sampling is increased from 12 to 16 samples per cycle (s/c).

3.4. Impact of the Magnitude Estimator

Microprocessor-based relays calculate their operating signals, such the current magnitude for the IOC function, from raw signal samples. This process of estimation can include digital filtering for removal of the dc offset that otherwise would result in an overshoot. Typically a Fourier-type or RMS-type estimators are used.

The former extract only the fundamental component from the waveforms (60Hz) through a process of filtering. This would result in a much lower estimate of the magnitude if the waveforms were heavily distorted.

The latter extracts the total magnitude from the entire signal spectrum yielding a higher response under heavily saturated waveforms. The difference can be tenfold in extreme cases such as the ones considered in this paper.

Figure 15 shows an example of the estimation of a true RMS value. Please note that the relay is subjected to 64kA of fault current, and measures "only" 10-15 pu of current (50-75A secondary, or 500-750A primary). This is only about 1% of the true current, but still 10-15 times relay rated current.

3.5. Impact of the IOC Comparator

The derived operating current signal is compared against a user set threshold. Extra security may be implemented by requiring several consecutive checks to confirm the trip ("security counters"). This impacts when and for what current the relay would operate.

Fig.9.
Impact of a linear analog filter on the saturated current waveform (64kA fault current; C10, 50:5, CT with 0.2ohm burden).

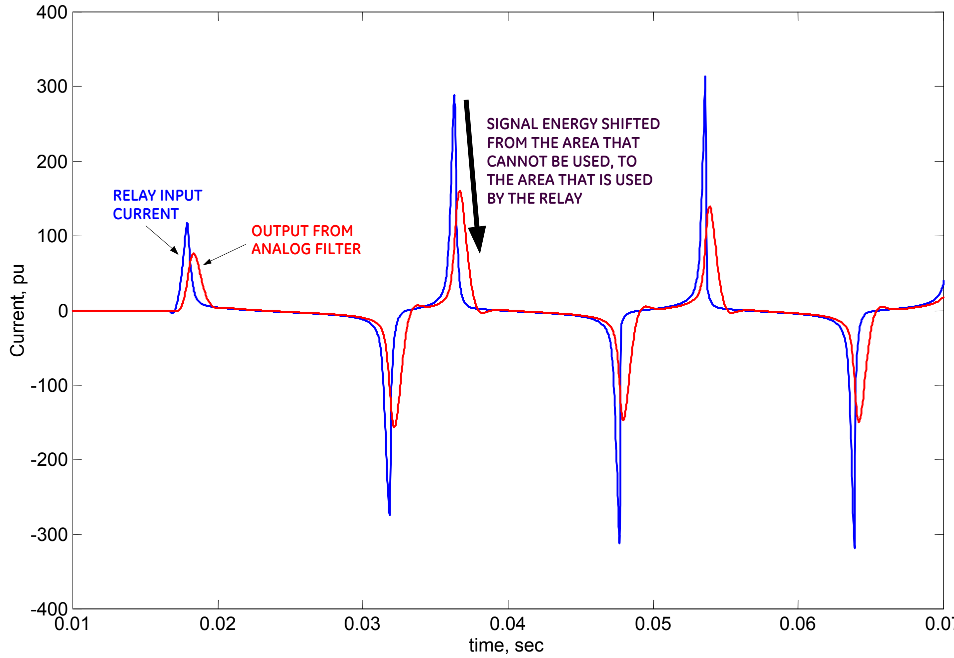


Fig.10.
Impact of a linear analog filter on the saturated current waveform (a simplified model of a non-linear filter).

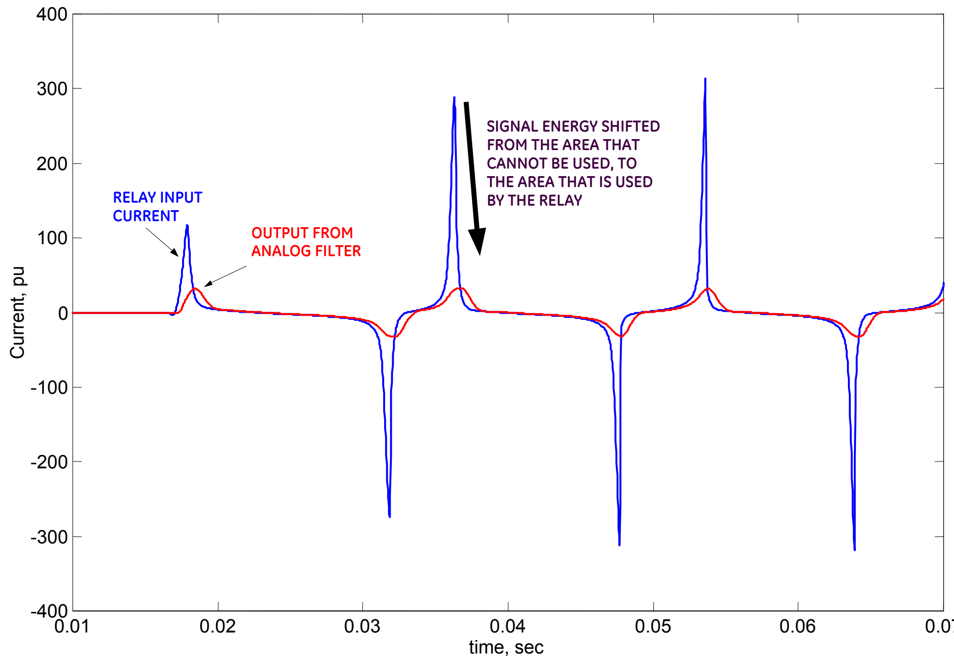
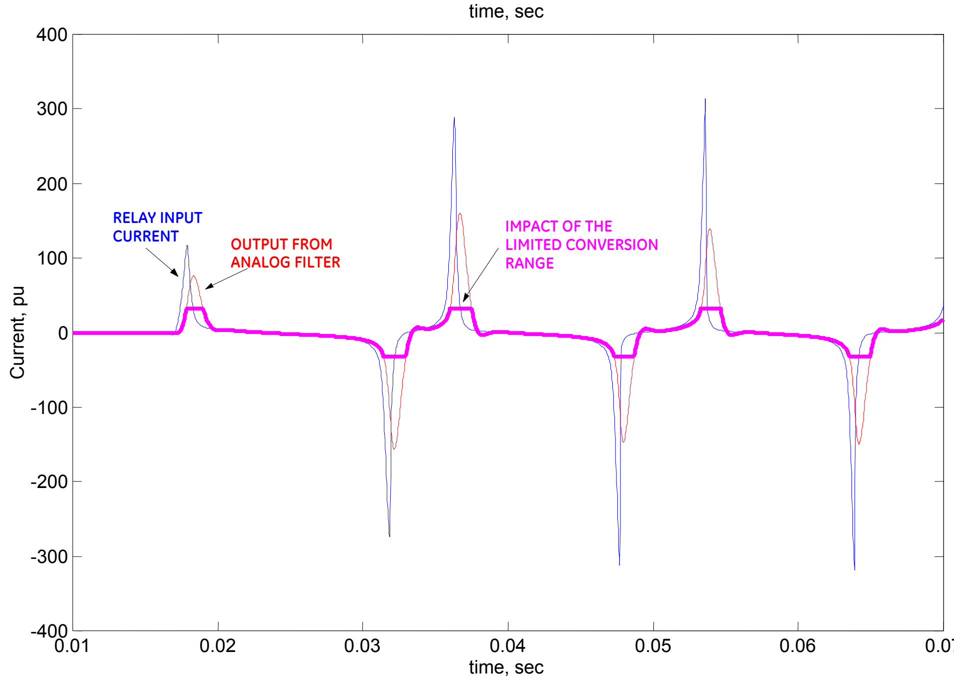


Fig.11.
Impact of the A/D converter – clamping (case of Fig.9).



Another aspect is the rate at which the operating conditions are checked. They may be executed with each new sample, every other sample, once a cycle, etc. ("protection pass"). This again impacts if and when a given function operates if the current is not steady.

Intimate knowledge of the relay inner workings is required to analyze this, as well as the previously discussed aspects of the relay response.

The next section proposes a methodology for reduction of the many factors impacting response of a given relay to waveforms produced by a given CT in order to facilitate practical analysis and application in the field.

4. Method of Quantifying Response of IOC Protection Under CT Saturation

This section presents a methodology for reduction of the many factors impacting response of a given relay to waveforms produced by a given CT in order to facilitate practical analysis and application in the field.

As shown in the previous subsection, any given relay reduces the signal coming from the CT to a series of pulses. These pulses are further limited in magnitude by the conversion range of the relay, while their duration is impacted by the natural inertia of the analog input circuitry of the relay (input transformers, analog filters). As a result considerable variability is removed in the A/D samples in response to the CT parameters. Additionally, a typical relay applies averaging when deriving its operating quantities (such as the true RMS). This reduces variability even further.

Fig.12.
Impact of the A/D converter – sampling (case of Fig.9).

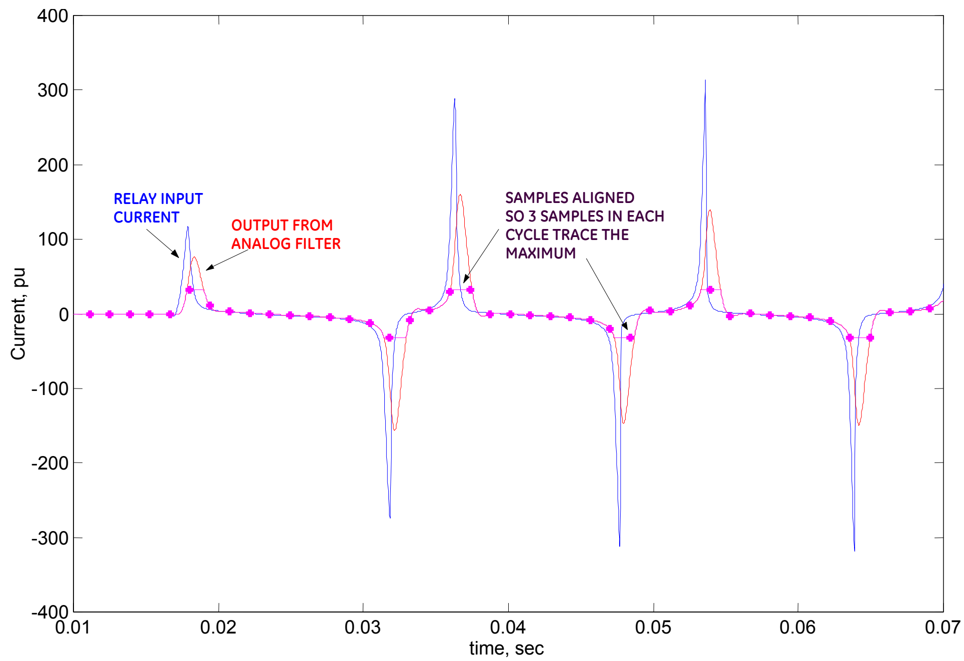


Fig.13.
Impact of the A/D converter– samples aligned differently compared with Fig.12.

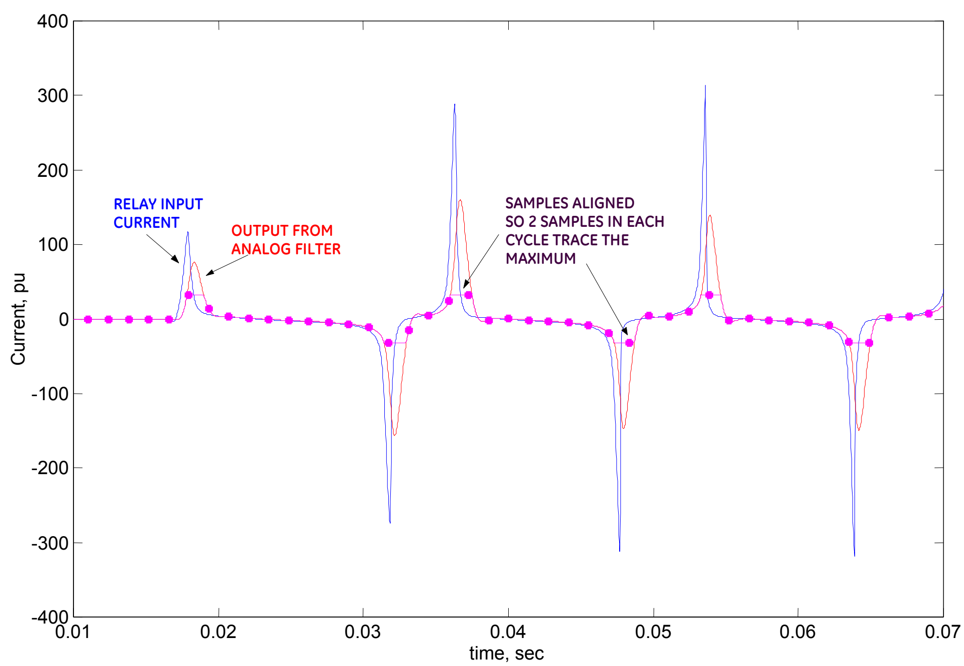


Fig.14.
Impact of the A/D converter – higher sampling rate (case of Fig.9).

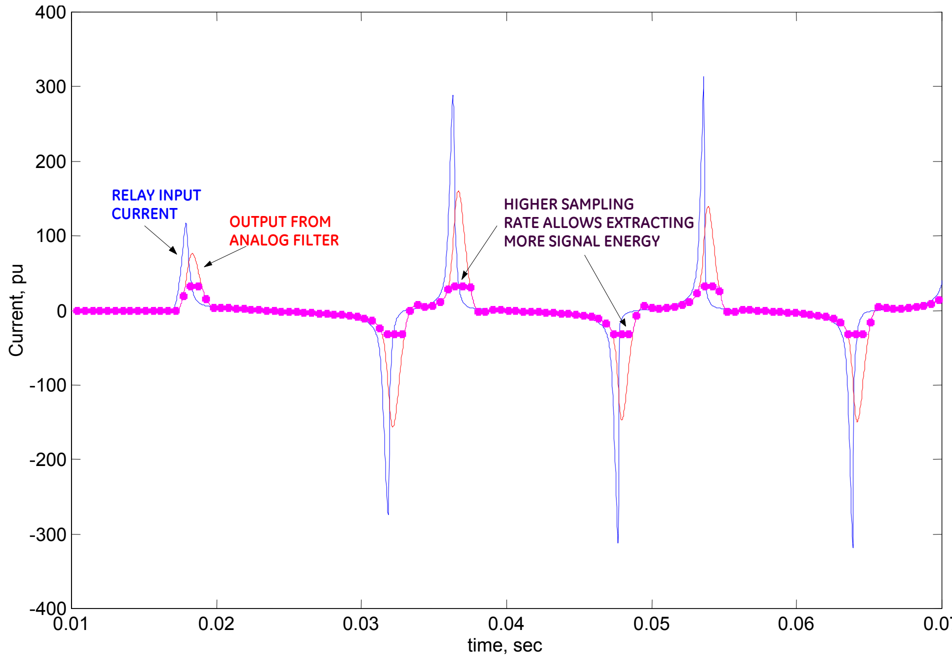


Fig.15.
Example of amplitude estimation – true RMS algorithm (case of Fig.9).

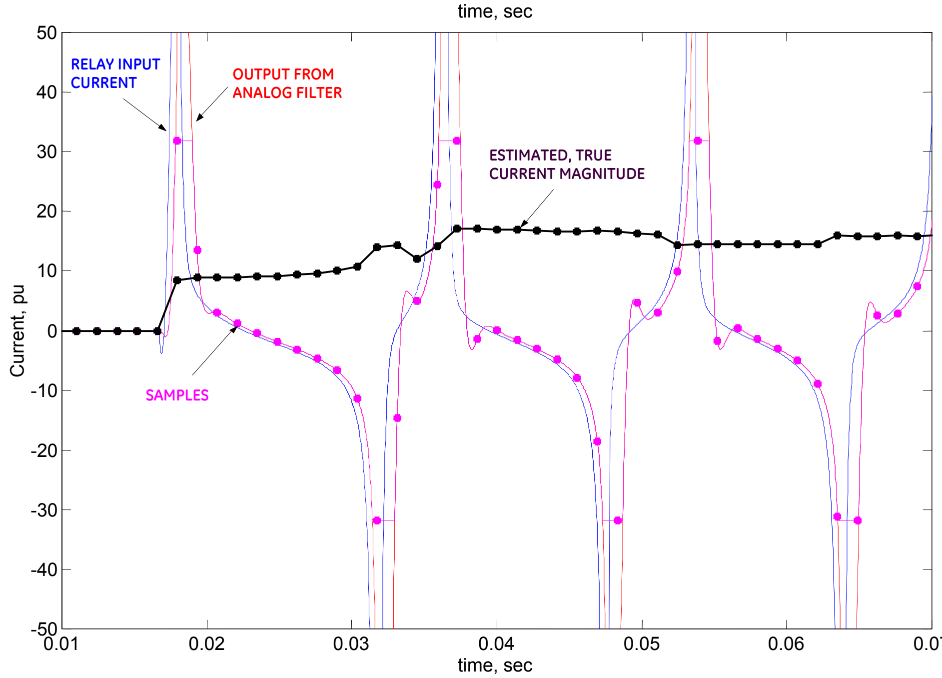
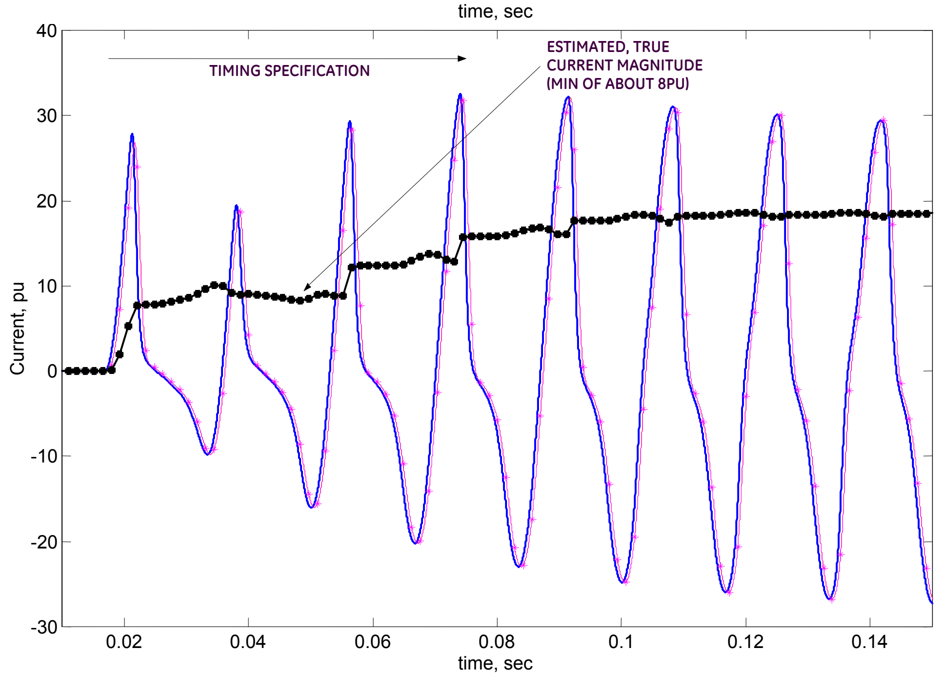


Fig.16.
50:5, C10 CT feeding a relay. Fault current of 1kA (20 times rated).



The above observation facilitates the following method of quantifying response of any given relay to any given CT. The method starts with a portion to be completed by relay manufacturers as follows:

1. Assume a nominal burden of a given CT. Under different burden, a given CT could be always re-rated by the application engineer based on the known principles.

2. Simulate the CT with and without dc offset in the primary current. Assume a typical X/R ratio for industrial applications (X/R = 15). Repeat for different ratios if required.

3. Vary the ac component in the primary current from the CT rated value up to 64kA.

4. Use a digital model of a given relay, or the actual relay, to find the operating quantity of an IOC function for a given fault current. When simulating, consider the minimum measured value within the timing spec of the IOC function. When testing the actual hardware, look for consistent operation within the timing specification of the relay.

5. Vary the alignment of samples with respect to the waveform in order to get the worst-case scenario. When simulating, explicitly align the samples in different patterns. When testing the actual relay, repeat the test several times to make sure the relay operates consistently.

6. The value found in step 5 is the highest setting that could be used for the IOC function to guarantee operation within the timing specification for a given fault current. This pair of fault current / maximum pickup setting becomes a point on the 2D chart.

7. Repeat the above for various fault currents. The obtained points constitute a characteristic for the considered CT and relay.

Fig.17.
50:5, C10 CT feeding a relay. Fault current of 10kA (200 times rated).

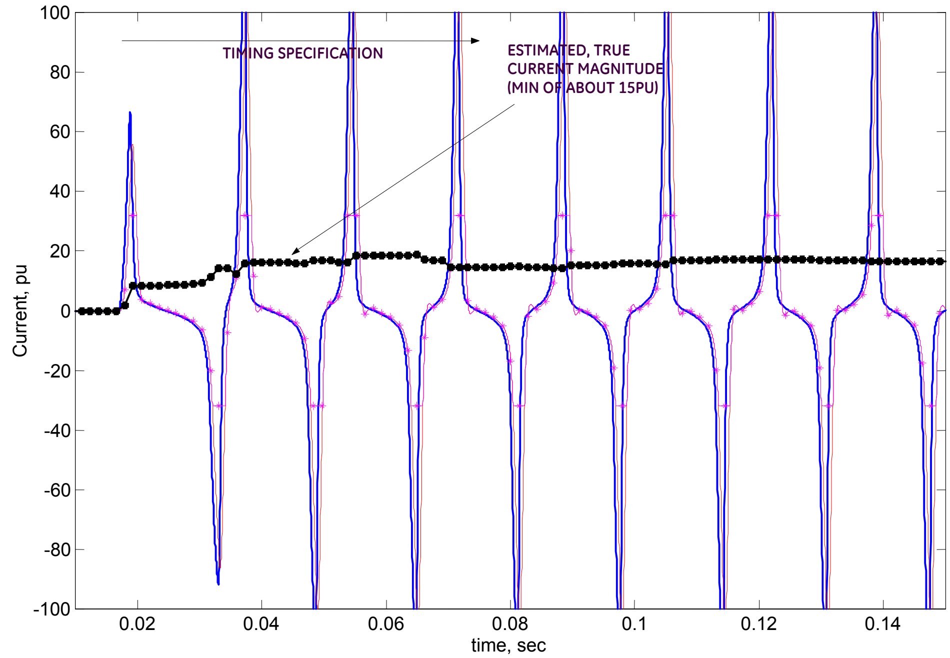
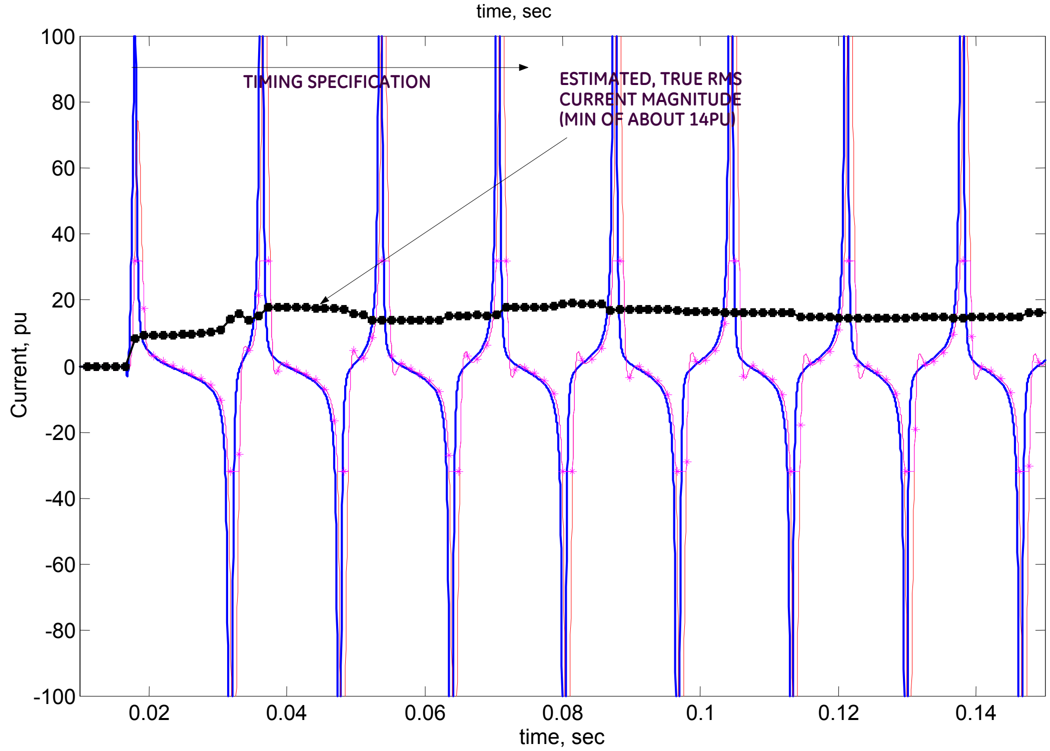


Fig.18.
50:5, C10 CT feeding a relay. Fault current of 50kA (1000 times rated).



8. Repeat the above for various CTs obtaining a series of characteristics for the considered relay.

Figure 16 shows the important signals for a certain relay fed from a 50:5 C10 with 0.2ohm burden under the symmetrical fault current of 1kA (or 20 times rated). Please note that this particular plot is for a burden different than nominal. The Figure shows that the relay would operate for this case within the timing specification as long as the setting is below 8pu. The (20pu,8pu) pair becomes a dot on the chart.

Figure 17 shows the same relay and CT under the current of 10kA (or 200 times rated). The Figure shows that the relay would operate for this case within the timing specification as long as the setting is below 15pu. The (200pu,15pu) pair becomes a dot on the chart.

Figure 18 shows the same relay and CT under the current of 50kA (or 1000 times rated). The Figure shows that the relay would operate for this case within the timing specification as long as the setting is below 14pu. The (1000pu,14pu) pair becomes a dot on the chart.

Repeating this for various fault currents, with and without dc offset, while varying the alignment between samples and waveforms, and plotting these as dots on the chart would divide the fault current / pickup plane into three regions: solid operation (A), intermittent or slow operation (B), and no operation (C) as depicted in Figure 19.

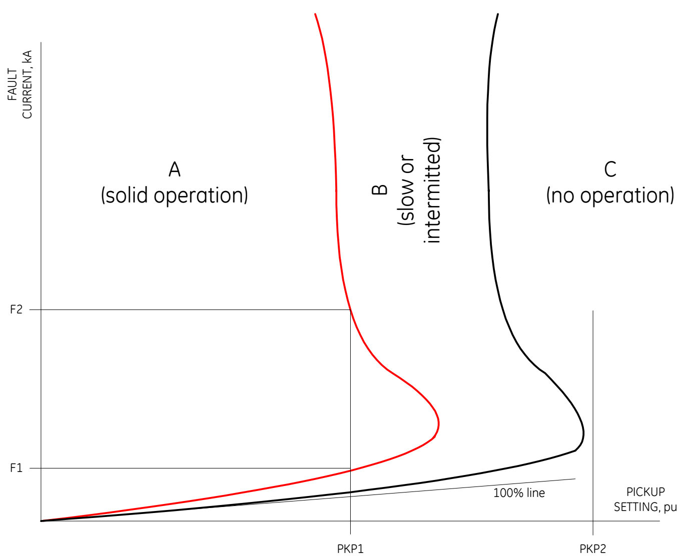


Fig.19.
The concept of "fault current – IOC pickup" curves.

The fault current – IOC pickup curves are interpreted as follows: if the CT were perfectly linear, and the relay had an infinite conversion range, the relay would see exactly 100% of the actual primary current, and would operate if the fault current equals the entered IOC setting. This would constitute a straight line as shown in Figure 19. Due to CT saturation and the finite relay range, the relay sees less than the actual (ratio current), and thus needs more current than 100% of the setting in order to operate. Therefore, the curves climb up away from the 100% line.

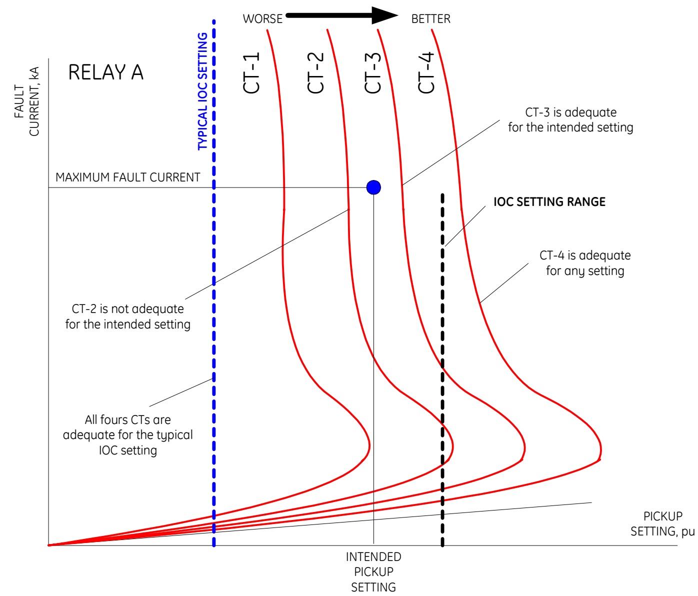


Fig.20.
The concept of fault current – IOC pickup curves: Selecting CT for a specific relay, specific maximum fault level and specific pickup setting.

If set to PKP1, the relay would operate as long as the fault current is above F1 value (crossing the pickup line), and the fault current is below F2 value (severe saturation decreasing the relay operating current below the pickup value).

If set to PKP2, the relay would never operate, because the operating value never goes above the PKP2 value: first, the current is to small; next the current is too large causing enough saturation to keep the operating quantity low.

Solid (guaranteed) operation of the IOC functions is of primary interest here. Therefore, the left line dividing solid operation form the intermitted operation shall be provided to the users as shown in Figure 20. Charts for different CTs shall be included on the same graph.

The user applies the chart as follows.

For an intended pickup level the user reads the fault current from the curve. If a fault of this magnitude happens, this particular relay fed from this particular CT would see just enough current to operate. This point defines the boundary of safe operation. If the actual maximum fault current is below that value, the application is safe; if above, the relay may trip slow or not at all for currents above the value from the chart.

If the application has a problem, the user could use a better CT. A family of curves shall be provided for various CTs. A CT shall be selected with the characteristic to the right of the intended pickup – maximum fault current point.

Please note that given the maximum fault current in Figure 20, CT-4 is adequate for any setting value (the CT-4 curve is located to the right from the maximum relay setting line). The CT-4 of this example is the lowest class / ratio CT that does not limit at all application of this particular relay. Vast majority of CTs of a given series fall into this category, and the curves are really needed only for the CTs below this borderline case.

Please note that given the typical IOC setting of 12pu or so used for short circuit protection of motors, all four CTs in the example of Figure 20 are adequate (even the CT-1 curve is located to the right from the typical setting line).

To understand better application of the curves, consider a relay and two CTs as in Figure 21. Assume a setting of 19pu is to be used on this particular relay fed from CT-1 on the bus with short circuit capacity of 50kA. Because the 50kA/19pu point is outside the CT-1 curve, this application is not secure. With this setting the relay would operate reliably up to the fault current of 15kA. This CT could be used with settings below 17.5pu.

If the 19pu setting is a must, and the short-circuit capacity is 50kA, CT-2 shall be used. It's curve is to the right of the 50kA/19pu point, meaning the relay would always operate for faults fed from this bus with a setting of 19pu.

Assume the CT-2 is used with this relay: The highest setting one could apply under any practical fault level is 21pu.

As illustrated above, the proposed fault current – pickup chart is a powerful tool to evaluate and adjust applications of IOC protection with low-ratio CTs.

The method can be used not only to match CTs to relays, but vice versa as well. For a given CT a series of curves can be produced that show the maximum allowable IOC setting for different relays and different fault current levels.

The CTs on the fault current – pickup charts shall be presented assuming nominal burdens. For varying burdens, the CT will get re-rated by an application engineer based on the well-known principles. For applications with long leads, the charts play a role in selecting proper wires in order to meet the required performance.

Fig.21.
Using the fault current– pickup setting charts.

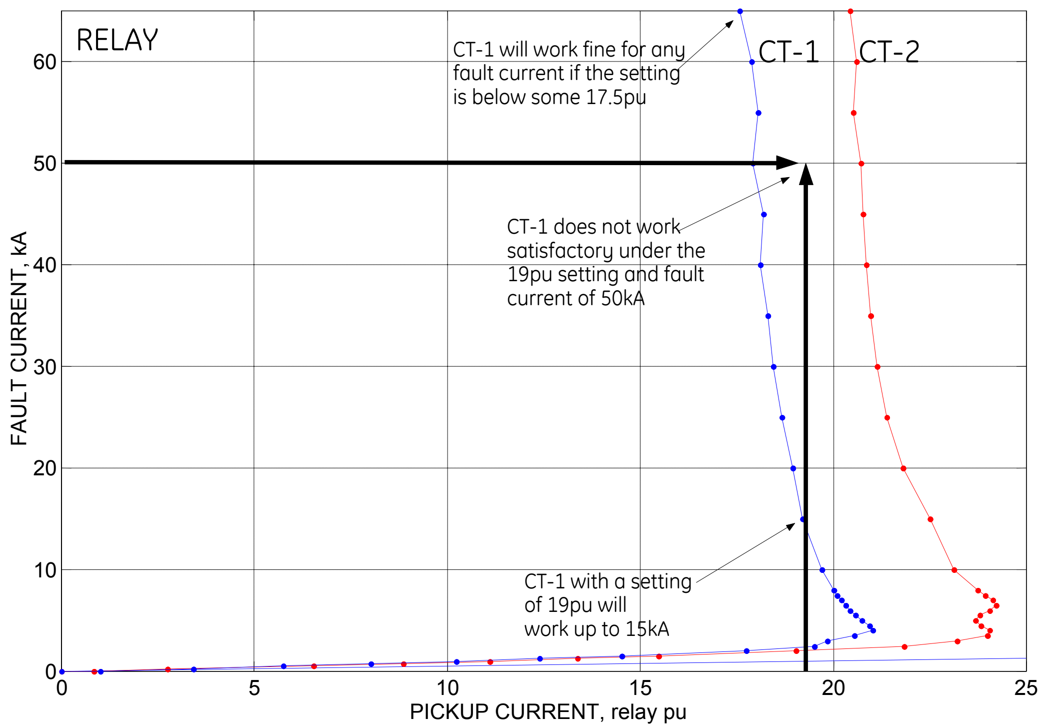


Fig.22.
Fault current – pickup charts for the 469 relay (f/w 5.0, h/w rev. I) and two sample CTs (relay setting range for IOC is 20pu). Application in 60Hz systems.

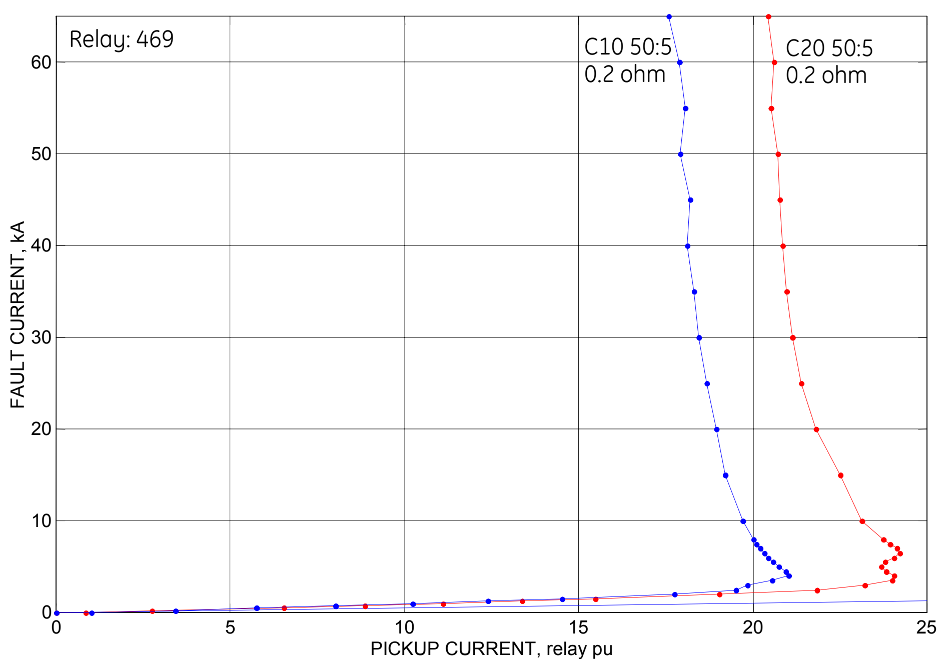


Fig.23.
Fault current – pickup . charts for the 489 relay (f/w 1.53, h/w rev. I) and two sample CTs (relay setting range for IOC is 20pu). Application in 60Hz systems.

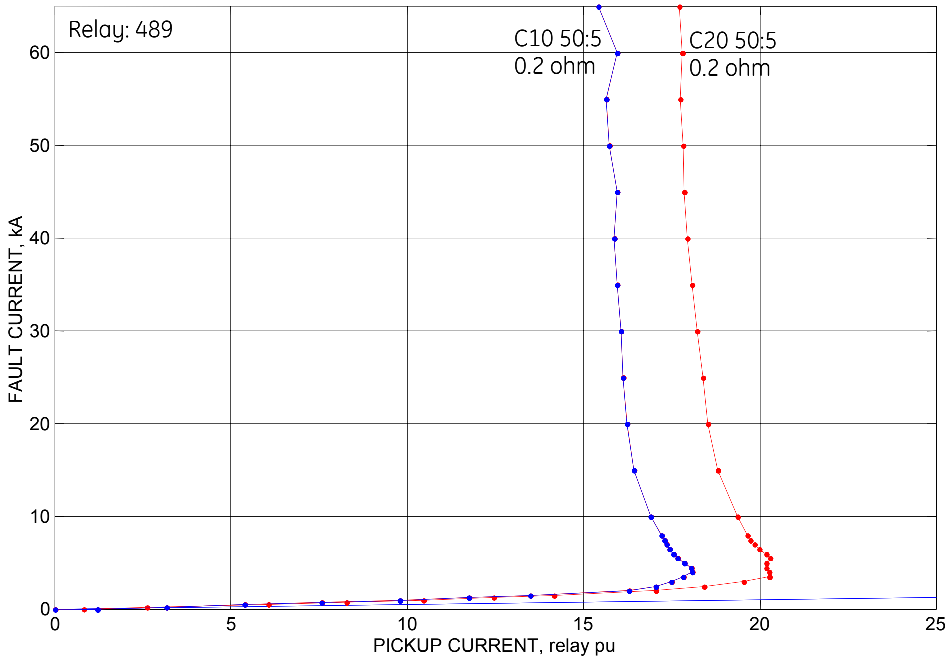


Fig.24.
Fault current – pickup charts for the 369 relay and two sample CTs (relay setting range for IOC is 20pu). Application in 60Hz systems.

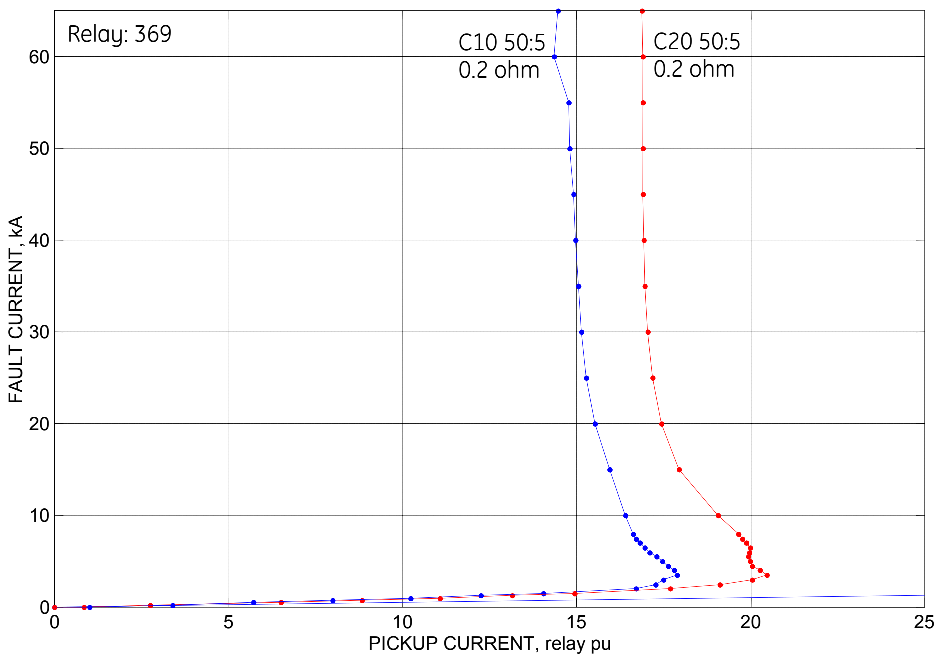
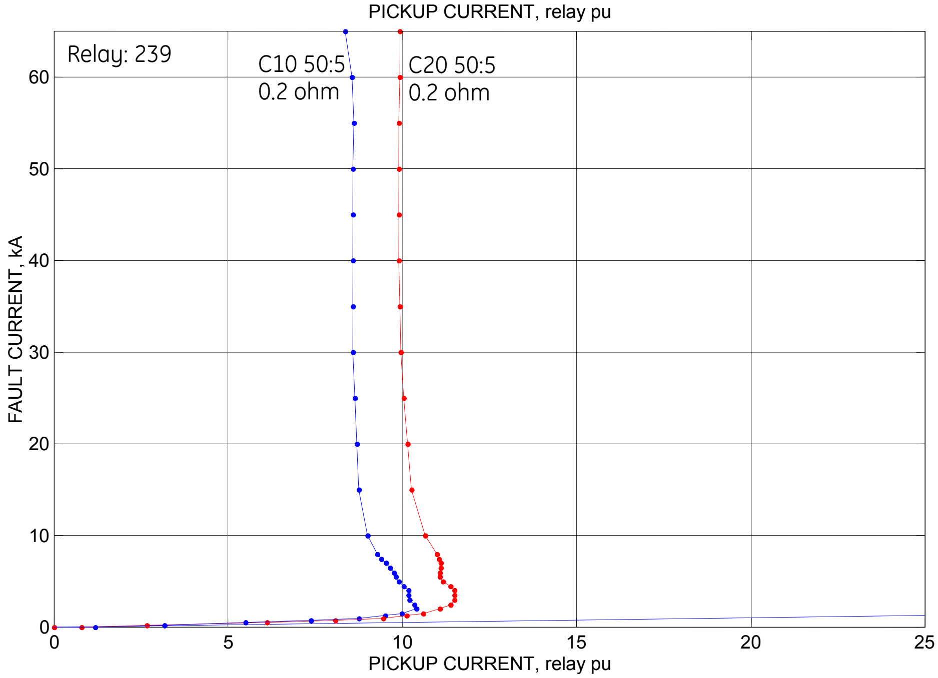


Fig.25.
Fault current – pickup charts for the 239 relay and two sample CTs (relay setting range for IOC is 11pu). Application in 60Hz systems.



5. Analytical Analysis of Selected MULTILIN Relays

Several MULTILIN relays have been evaluated based on the approach outlined in the previous section. The evaluation assumes simplified model of relays giving consideration to their actual analog filters, conversion ranges, sampling rates, digital filtering and phasor estimators.

The analysis has been presented for 2 selected CTs (50:5, C10, 0.2ohm burden, and 50:5, C20, 0.2 ohm burden). Note, that these are relatively poor performance CTs. With the burden of 0.2ohms, the first CTs is equivalent to a "C5 class".

Figures 22 through 26 present the fault current – pickup charts for the 469, 489, 369, 239 and 750 relays.

It is clear from the figures that using very low-ratio CTs prevents applying the relays with settings above some 80% of the setting range. For example, with the 50:5, C10, 0.2 ohm CT applied in a 64kA switchgear, the 469 can be set as high as 17pu. The typical setting is considerably lower (some 12pu) which makes the application secure.

6. Test Results for Selected MULTILIN Relays

The analysis of section 5 has been validated on the actual relay hardware. Figures 27 and 28 present results (for currents up to 200 times the rated) for the 469 and 369 relays. It could be seen that the theoretical prediction and response of the actual relay match well in the tested region of the chart.

The relays have been tested as follows: A given saturated waveform is played back to the relay; an IOC setting is decreased from the maximum available on the relay to the point when the relay starts operating consistently, and all responses are within the published trip time specification. This setting is considered a solid operation point. The fault current – solid operation pickup

Fig.26.
Fault current – pickup setting charts for the 750 relay and two sample CTs (relay setting range for IOC is 20pu). Application in 60Hz systems.

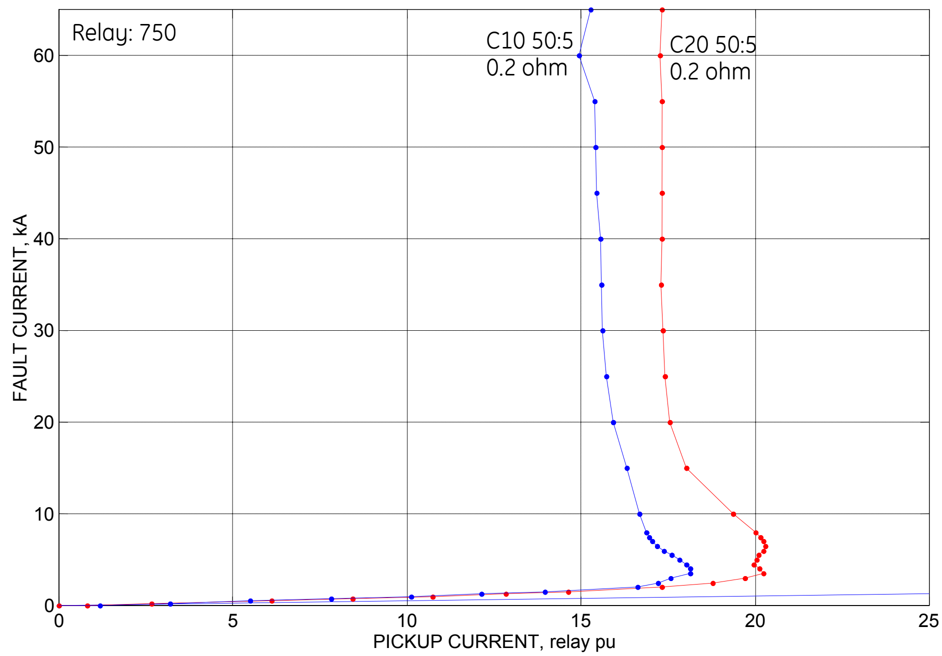
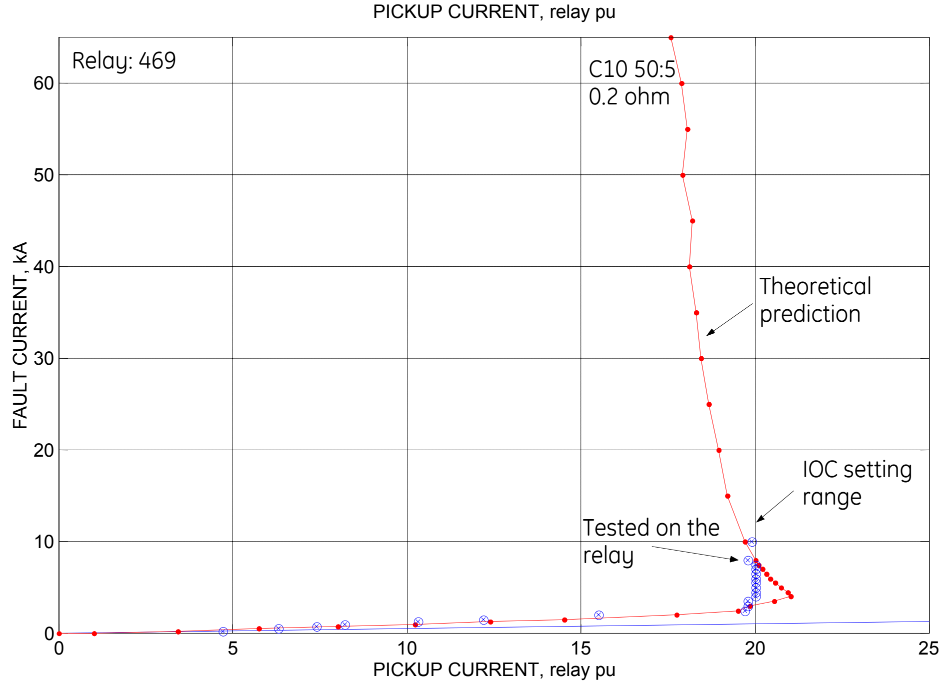


Fig.27.
Fault current – pickup charts for the 469 relay (f/w 5.00, h/w rev. I) and a sample ITI CT (theoretical analysis vs relay test results). Application in 60Hz systems.



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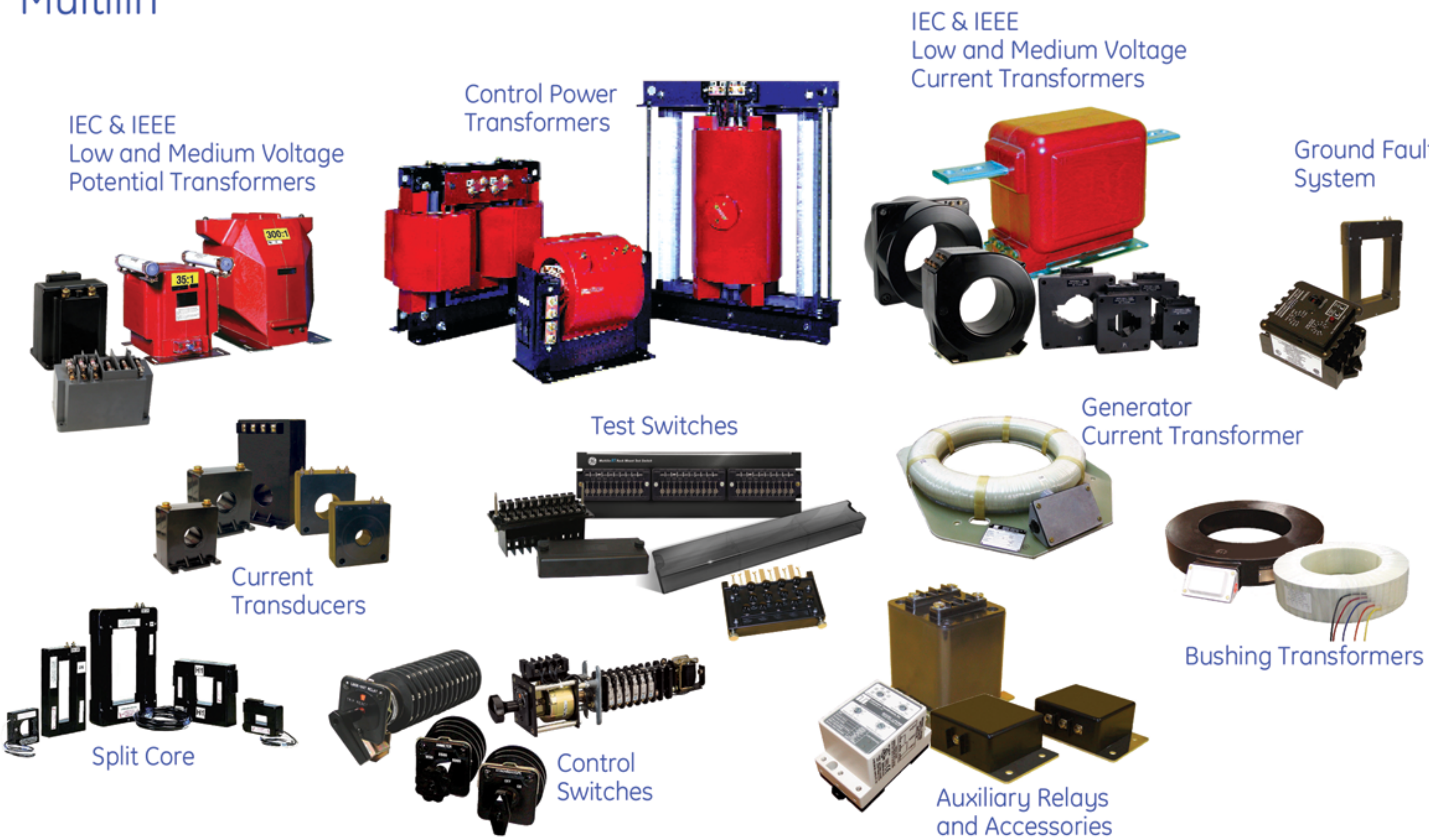

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point is put on the chart, and the process continues with the next fault level.

The relays were tested using playback of waveforms generated from a digital model of the CT. This model was verified as well in order to gain absolute confidence in the accuracy of the presented charts.

7. Validation of the CT model

Using an adequate CT model is critical to the accuracy of the analysis. CT modeling techniques are relatively precise when applied in the typical signal ranges, i.e. under currents up to few tens of the CT rated current. This paper assumes currents in hundreds of the rated value, and therefore calls for cautious approach to CT modeling.

The CT model used in this study is supported by the IEEE Power System Relaying Committee, and has been verified by multiple parties. It is justified to assume, however, that the verification was limited to relatively low current levels. The model shall be verified on fault currents as high as 800 rated in order to make sure the unusually high flux densities, and other aspects do not change the nature of the CT response compared with more regular situations. This must be done using actual CTs and high power testing equipment.

This section compares test results of a 50:5 C10 and a 50:5 C5 CT with the waveforms obtained from the digital model, in order to validate the model. The comparison is done for currents being hundreds of the CT rated.

The tests have been done in the high power lab of GE Multilin's Instrument Transformers (ITI) division in Clearwater, Florida. Figures 30 and 31 show a CT under test, and the test setup, respectively. A current source capable of driving 5kA of current is connected to 4 primary turns on the C10 CT. A current source capable of driving approximately 3.6kA of current is connected to 11 turns on the C5 CT. This is equivalent to testing the C10 CT with 20kA of primary current, and the C5 with 40kA of primary current. A 0.2ohm burden resistor is applied to both transformers.

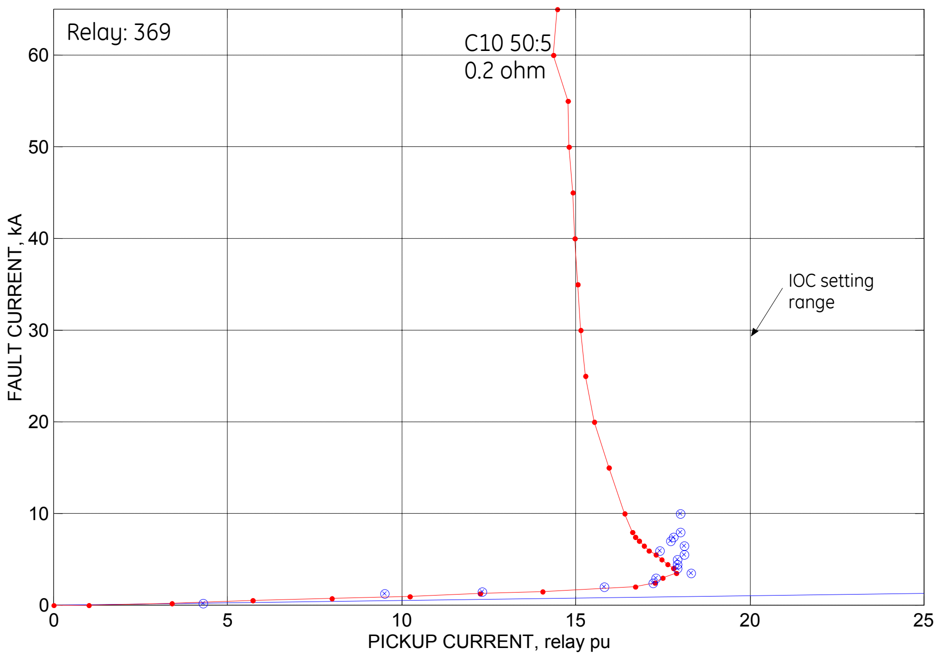


Fig.28.
Fault current – pickup charts for the 369 relay and a sample CT (theoretical analysis vs relay test results). Application in 60Hz systems.

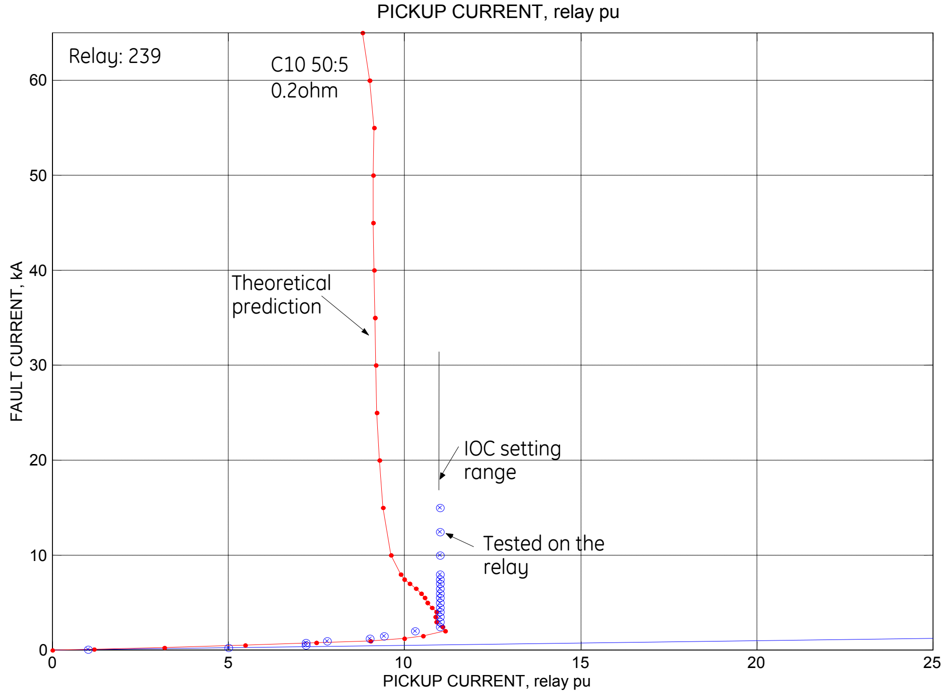


Fig.29.
Fault current – pickup charts for the 239 relay and a sample CT (theoretical analysis vs relay test results). Application in 60Hz systems.

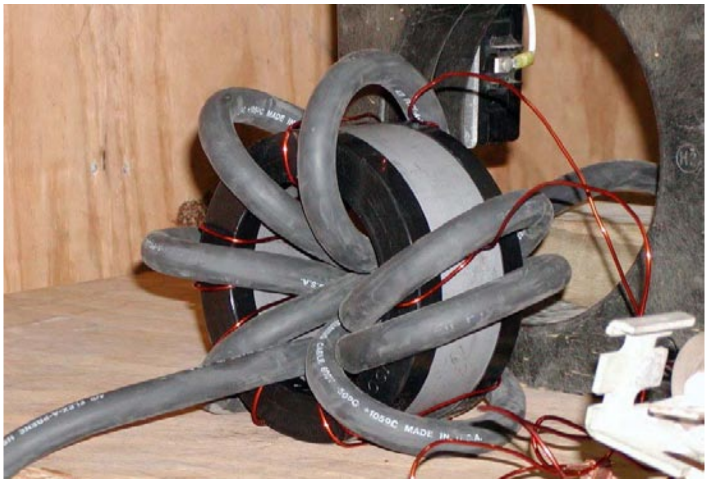


Fig.30. 50:5 C5 CT under test. Multiple primary turns (8 cable loops indicated) used to simulate effectively higher primary current. The reference CT is visible to the right of the CT under test.

Fig.31. Test setup.

A digital scope is used to record traces of the ratio and secondary currents. A 0.3B1.8, C100, 4000:5 CT is used as a reference CT measuring the primary current.

The tested CTs are demagnetized before each test in order to facilitate the simulation by making the residual flux known (zero).

Figure 32 presents the actual (measured) magnetizing characteristics for the two CTs under test.

Figures 33 shows the primary currents: measured and simulated for a sample 20kA test of the C10 CT.

The current source used in the test cannot be controlled as to the dc offset. Therefore, the primary waveform in the digital simulation has been matched post-mortem to reflect the test waveform.

Subsequently, such primary waveform has been used to exercise the digital model of the CT producing the secondary waveform depicted in Figure 34. The tested and simulated secondary currents waveforms are inverted in the figure to better indicate the narrow current pulses that otherwise would overlap closely and be difficult to read.

The primary current of Figure 33 is distorted and does not follow a classical exponential dc decay model. This is because of the type of the current source used. The dc constant and distortions are of secondary importance, however, because of the high value of the current.

As seen in Figure 34, the model and actual CT tests match well. The model seems to yield a slightly lower magnitude of the secondary current, and at the same time, slightly narrower pulses of the current. The difference in magnitudes seems to be within 10-15%, and is not critical as this level is several times above the relay cut-off value already. The lower magnitude and width of the pulses as simulated by the digital model make the analysis of this report conservative – the actual CT would deliver more energy to the relay compared with the simulated CT.

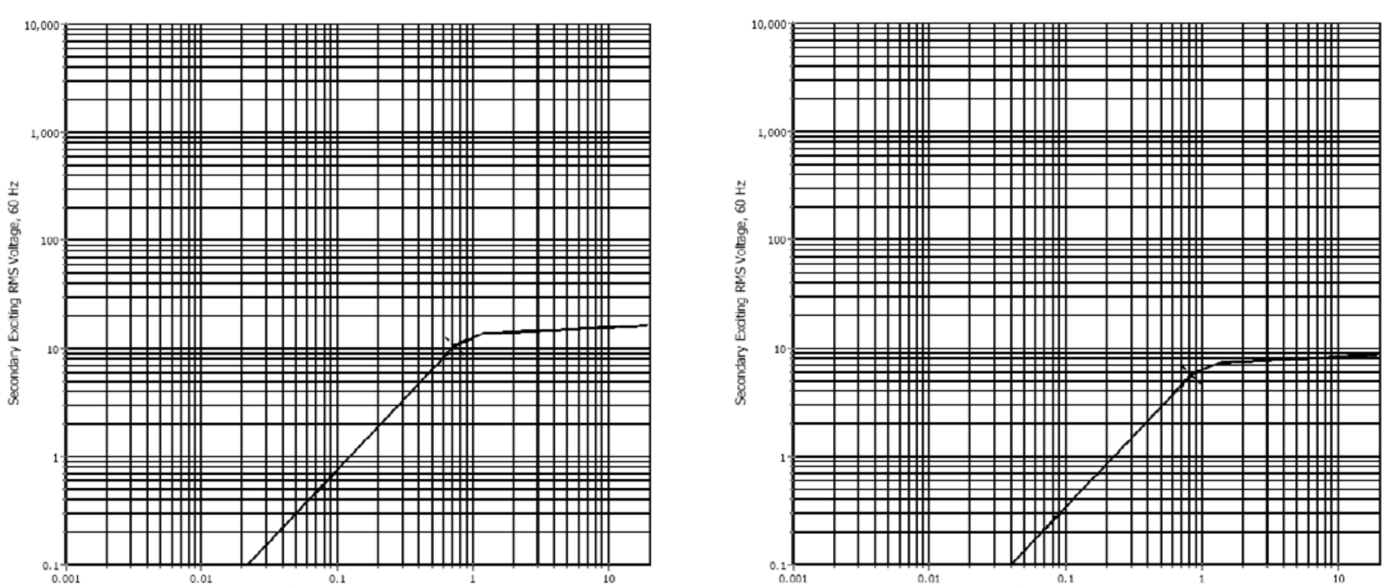


Fig.32. Magnetizing characteristics of the C10 (top) and C5 (bottom) CTs used in the tests.

Figure 35 shows a 10kA test of the C10 CT. Again, the model and the test results match well.

Figure 36 shows a 32kA test of the C5 CT. This approximates a 64kA test of a C10 CT. As seen in the Figure, the CT still delivers current pulses of 300A secondary. Again – the digital model seems to return current pulses of shorter duration, making the analysis of this report conservative.

8. Conclusions

This document explains issues associated with instantaneous overcurrent protection in industrial applications when feeding protective relays with low-ratio CTs. Extreme cases of CT saturation have been considered to the extend of 64kA of fault current measured by a 50:5, C10 CT.

A methodology has been provided for practical field engineering of CT and relay applications. Simple to understand and apply charts could be developed as illustrated in this report to quantity a problem, and rectify it if necessary. The proposed methodology eliminates many variables from the analysis, does not require users to apply any sophisticated tools, and is easy to use.

Results of analysis and testing indicate that the combination of low-ratio CTs and very high fault currents could prevent the user from entering very high IOC settings. For a given relay, working with a given CT, in a system with a given maximum short circuit level, a maximum IOC setting can be found for which the relay will operate within its timing specifications. If a higher setting is required, the relay may respond outside of the spec or restrain itself from tripping. That region of inadequate operation is relatively limited, and occurs only for absolute extreme cases of low-ratio CTs and high fault currents. Moreover, the practical settings are outside of the affected region.

This explains why one does not encounter this problem in the field. On the surface the problem seems to be very serious – the secondary currents are extremely low compared with the

Fig.33.
Case 1 – primary currents: test (dotted) and simulation (solid). A 20kA test of the C10 CT.

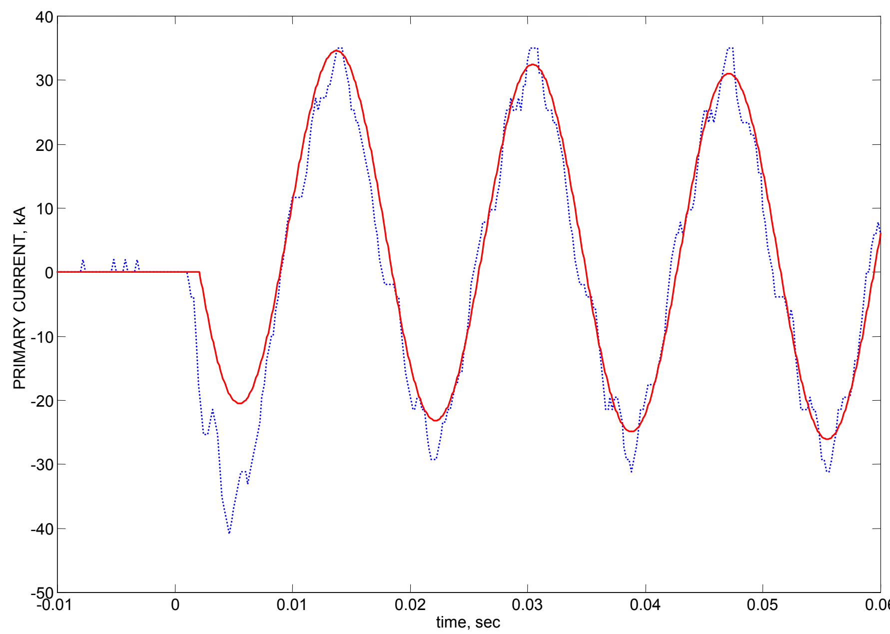
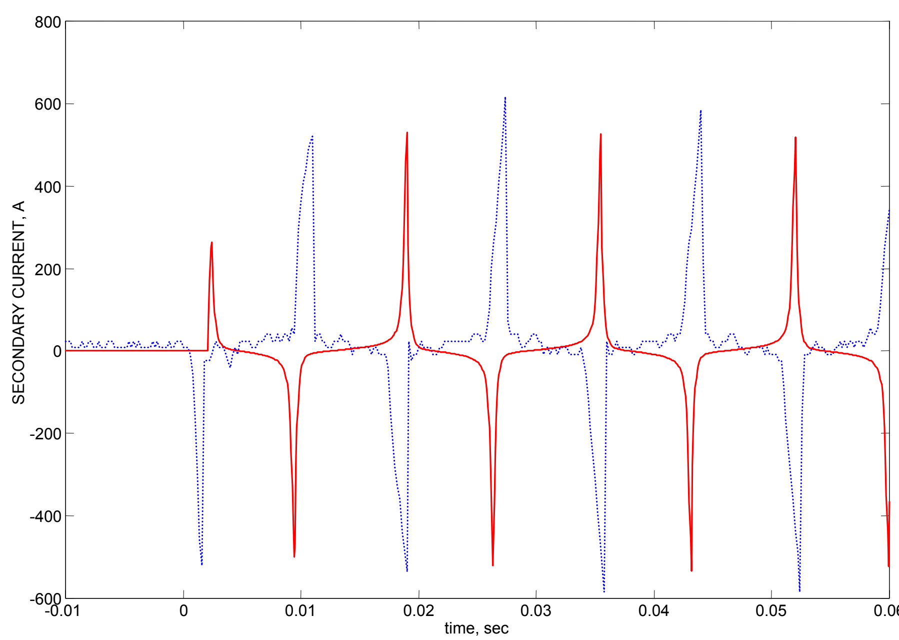


Fig.34.
Case 1 – secondary currents: test (dotted) and simulation (solid). The currents are inverted for better visualization. A 20kA test of the C10 CT.



ratio currents. However, these secondary currents are still high enough to activate relays given their practical setting ranges.

The above could be better understood when realizing the source of the problem. A given CT saturates heavily because its ratio is selected to match relatively small load current. If the load current is small, the overcurrent pickup threshold for short circuit protection is small as well (it is a fixed multiple of the load current). The magnitude of extremely high fault currents is a hundreds times, or close to a thousand times the rated current, but this means it is tens or hundreds times the pickup settings. Under such high multiples of pickup, a relay has a large margin between the operating current and the setting. The operating signal will have to be decimated by tens or hundreds times by CT saturation and limited conversion range of the relay, to cause the relay to fail.

It must be emphasized that there is a dramatic difference between relays using Fourier-like approach (cosine and sine filter), and relays based on true RMS value. The latter behave significantly better as illustrated in this report.

This report uses the standard IEEE burden of 0.2 ohms for illustration. The actual burden in typical industrial applications is significantly lower, making sample results of this report conservative. In actuality the problem is less significant.

Using this methodology, users of GE Multilin's relays can apply them safely and confidently in applications where fault currents exceed rated currents by hundreds of times, even if low-ratio CTs have been used.

Fig.35.
Case 2 – secondary currents: test (dotted) and simulation (solid). The currents are inverted for better visualization. A 10kA test of the C10 CT.

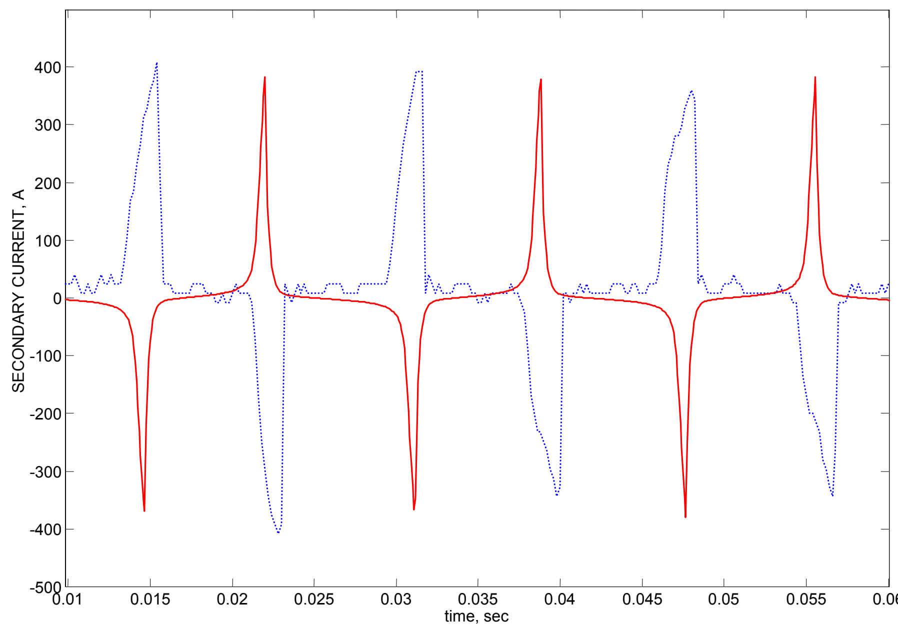
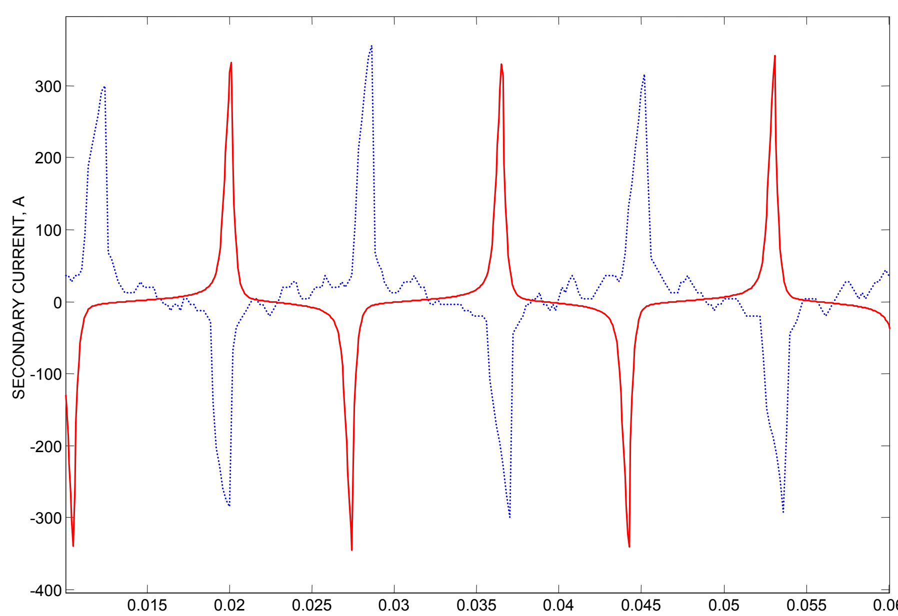


Fig.36.
Case 3 – secondary currents: test (dotted) and simulation (solid). The currents are inverted for better visualization. A 32kA test of the C5 CT.



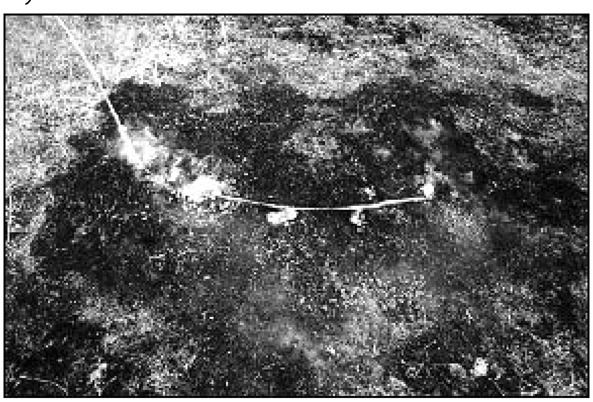
High Impedance Fault Detection On Distribution Feeders

Mark Adamiak, Craig Wester, Manish Thakur, Chuck Jensen

Abstract - The ability to detect High Impedance (HiZ) faults has been a topic of research and development for over 30 years. About seven years ago, products began to appear on the market that could *securely* perform this function. Over this time period, several hundred HiZ detection devices have been placed in service and have performed to expectations. This paper reviews the operating principle of HiZ fault detection, looks at the application issues encountered over this time, highlights some of the actual detections, and looks at possible future directions of the technology.

1. Introduction

From the beginning of power distribution, the power system protection engineer has been challenged with the detection of HiZ faults. The IEEE Power System Relay Committee working group on High Impedance Fault Detection Technology [1] defines HiZ faults as those that "do not produce enough fault current to be detectable by conventional overcurrent relays or fuses". As such, it should be noted that whereas traditional protection is designed to protect the power system, HiZ protection is primarily focused on the protection of people and property.



The typical HiZ fault is when a conductor physically breaks and falls to the ground. The break in the conductor will usually result in either a drop in load on the affected feeder or possibly a momentary overcurrent condition as the falling conductor briefly comes in contact with a solidly grounded object. Once on the ground, the resulting electrical signature is very much a function of the contacted surface. Surfaces such as concrete, grass, dirt, and wet surfaces in general will result in an "arcing fault" with RMS fault currents in the range of 10 to 50 amps whereas surfaces such as dry sand and asphalt will result in a constant low level of current flow. Arcing faults result in a very definable and detectable pattern whereas the signatures presented by the latter surfaces present a challenge to secure and reliable detection.

A related type of HiZ fault is when the conductor does not break, but comes into contact with grounded objects either through a failure of the conductor mounting system, insulation failure, or inadvertent contact with some external element such as a tree limb. These faults will usually exhibit the same "arcing" signature as a broken conductor lying on the ground, however, the event will not be preceeded by any change in fundamental current.

A third type of event is a sagging conductor. Although not technically a "fault", it does present a considerable public safety hazard. In this circumstance, a conductor hangs low enough to enable human or other contact. Note that this type of event offers no electrical signature for detection.

The frequency of downed conductors is a topic for discussion as most occurrences are not logged by field crews. Best estimates are that between 5% to 10% of all distribution system fault events are downed conductors. See below photo of downed conductor.

2. Detection Techniques

Detection of HiZ faults fall into two categories: mechanical detection and electrical detection. The following sections offer a brief review of the various techniques that have been developed in these areas.

a. Mechanical Detection

Mechanical detection usually involves some way of forcing contact with a solid ground in order to allow conventional overcurrent protection to operate.

The first type of mechanical HiZ detection method consists of a device(s) mounted to a cross arm or pole. The device is mounted under each phase wire in order to catch the conductor as it falls to the ground. The force of the falling conductor releases an internal spring that ejects a bus bar to make contact with the fallen wire and create a low impedance ground fault. The ground fault created will cause conventional overcurrent protection to operate. Sagging conductors that do not come in contact with earth or a grounded object could be detected by this mechanical method. The installation and maintenance costs are high. For bi-directional coverage, six units would have to be mounted on each pole. Even though the cost may be high to allow usage on every pole, utilities may install in certain areas, such as churches, schools, or hospitals.

A second type of mechanical HiZ detection method uses a pendulum mounted aluminum rod with hooked ends. It is suspended from an under-built neutral conductor. The falling conductor is caught and produces a low impedance ground fault, which operates conventional overcurrent protection. Typically, two units are mounted per span. Sagging conductors that do not come in contact with earth or a grounded object could be detected by this mechanical method. Ice, wind, and tree growth could cause a false detection.

b. Electrical Detection

There are three primary "algorithmic" techniques that have been developed and field tested to date. A summary of these three systems follows:

High Impedance Fault Analysis System

This electrical HiZ detection method measures the third harmonic current phase angle with respect to the fundamental voltage. There is a distinct phasor relationship between the third harmonic current and the faulted phase voltage. The device calculates and stores the average ambient third harmonic current phasor. When a fault occurs, the new third harmonic current phasor is vectorially subtracted from the stored value. A high impedance fault is issued if the magnitude is above setting and angle matches a predetermined value for a downed conductor. The device acquires current and voltage values from the relaying current and voltage transformers. Typically, one unit is installed in each distribution breaker. Units have been in service since the early 1990's.

Open Conductor Detection

This electrical HiZ detection method detects loss of voltage to determine a broken conductor. The system measures the voltage at each end of a single phase lateral. When the voltage of any phase drops below the specified threshold, a transmitter sends a signal on the neutral conductor to a receiver at the upstream device. The upstream device opens if voltage is present at the upstream device. Systems have been under test since 1992.

Signature Based HiZ Detection

The signature based HiZ IED performs expert system pattern recognition on the harmonic energy levels on the currents in the arcing fault. This technique is based on the technology developed at Texas A&M University after more than two decades of research, funded in part by the Electric Power Research Institute. The HiZ IED uses a high waveform sampling rate (64 samples/cycle) on the ac current inputs to create the spectral information used in the signature analysis. Expert system techniques are employed to assure security while maintaining dependability.

The overall process incorporates nine algorithms, each performing a specific detection or classification function. High impedance fault detection requires inputs from the three phase and ground currents via relaying current transformers. Voltage inputs are used to enhance security and to provide supplemental phase identification and are not required for arcing detection.

The primary detection algorithms are the Energy and Randomness algorithms. The Energy algorithm focuses on the fact that arcing causes bursts of energy that register throughout the frequency spectrum. The energy values – computed as the square of the harmonic and non-harmonic spectral components (excepting the fundamental) – are integrated into odd, even, and non-integer harmonics values. Sampling at 64 samples per cycle allows computation of frequency components up to the 25th harmonic. The Energy algorithm monitors these computed harmonics on all phase and ground currents. After establishing an average energy value for a given signal, the algorithm indicates "arcing" if it detects a sudden, sustained increase in the value of that component. Figure 1 shows "normal" energy levels as measured on an actual feeder. Indications of energy increase are reported to the Expert Arc Detector (EAD), which performs a probabilistic integration of the arcing inputs from all phases and all harmonic components.

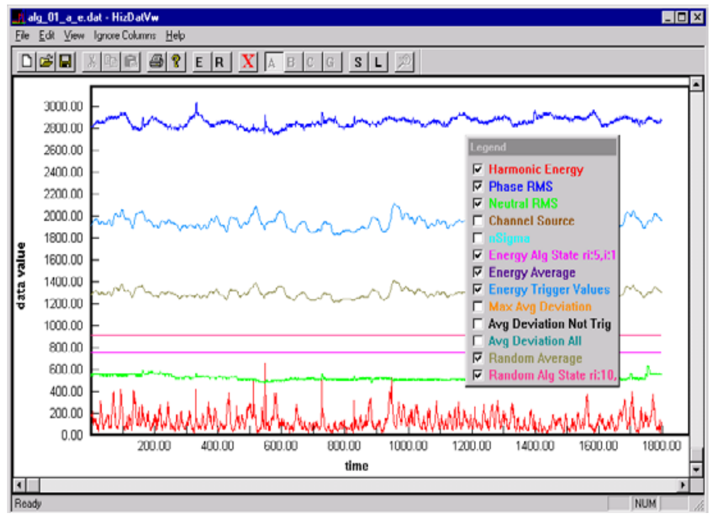


Fig.1.
Normal Energy Levels

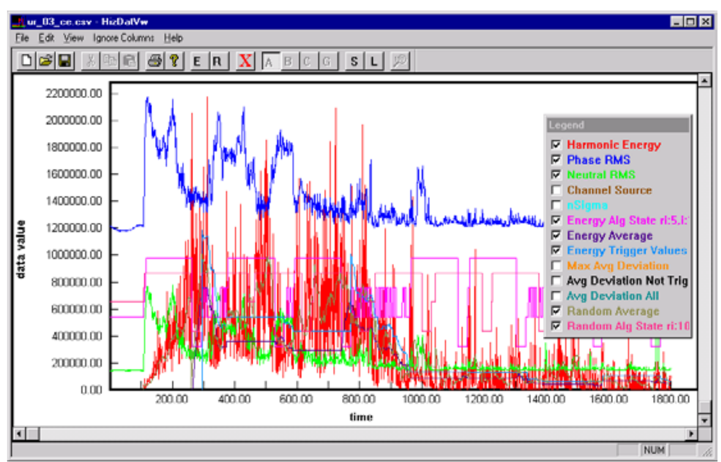


Fig.2.
Arcing Fault Energy Levels & Randomness Signature

The second detector in the algorithm suite is the Randomness algorithm. This algorithm keys on a second characteristic of an arcing fault, which is the fact that the energy magnitudes tend to vary significantly on a cycle-to-cycle basis. Figure 2 shows the energy values during an arcing fault. The high level of energy as well as the variance in the energy can clearly be seen. The Randomness measures these magnitude variations and report detection of magnitude variation to the Expert Arc Detector.

The purpose of the Expert Arc Detector algorithm is to assimilate the outputs of the basic arc detection algorithms into one cumulative arc confidence level per phase. There are actually 24 independent basic arc detection algorithms, since both the Energy and Randomness algorithms are run for the odd, even and non-integer harmonics for each phase current and for the neutral/ground current. An arc confidence level is determined for each phase and neutral/ground. The expert arc detector algorithm compares the cumulative arc confidence level values or high EAD counts to the user's arc sensitivity setting. Figure 3 shows the block diagram of how the Energy, Randomness, and Expert Arc Detector algorithms function together.

For the device to be secure and dependable, the Expert Arc Detector integrates the outputs from the Energy and Randomness algorithms. The number of times that the integration is performed is, as well as the integration level. depends on the arc sensitivity setting. The more sensitive the setting, the lower the integration level and the fewer integrations required.

An "arcing detected" output is issued once all the EAD requirements are satisfied. If either a loss of load or a momentary overcurrent condition is detected immediately before an "arcing detected" output is registered, the "downed conductor" output is set to indicate that there is actually a conductor on the ground.

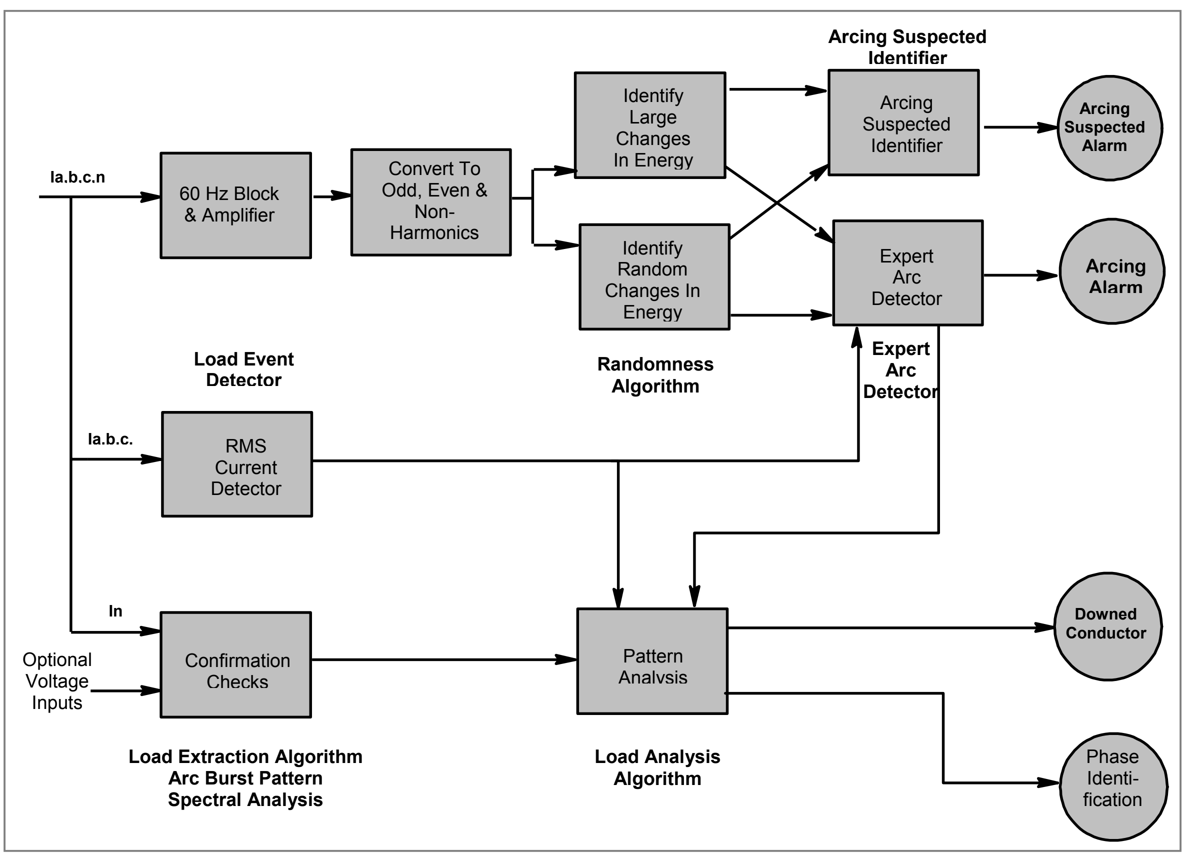
If the device determines that a downed conductor or arcing exists, it attempts to determine the phase on which the high impedance fault condition exists in a hierarchical manner. First, if a significant loss of load triggered the arc detection algorithms, and if there was a significant loss on only one phase, that phase is identified. If there was not a single phase loss of load, and if an overcurrent condition on only one phase triggered the algorithm, that phase is identified. If both of these tests fail to identify the phase, the phase with a significantly higher confidence level (e.g. higher than the other two phases by at least 25%) is identified. Finally, if none of these tests provides phase identification, the device analyzes the correlation between the peak portion of the voltage waveform with the neutral/ground arc bursts. If there is correlation with a particular phase voltage, that phase is identified. If that test fails, the phase is not identified.

Conductors that do not continuously arc, but have time periods between arcs can be detected by the arcing suspected identifier algorithm. For example, if arcing is caused by tree limb contact or insulator degradation, arcing will typically be present intermittently with relatively long periods of inactivity. In such cases, arcing may be affected by such factors as the motion of a tree limb or the moisture and contamination on an insulator. The purpose of the arcing suspected identifier algorithm is to detect multiple, sporadic arcing events. If taken individually, such events are not sufficient to warrant an arcing alarm. When taken cumulatively, however, these events do warrant an alarm to system operators, so that the cause of the arcing can be investigated. The user can select the number of maximum number of arcs and an acceptable period of time. Due to the possible long periods of arcing inactivity, a HiZ decision could be reached in up to 5 minutes.

3. Signature Based HiZ Application Issues

The following sections highlight a number of application guidelines developed over the last several years of HiZ detection device installations.

Fig.3. Signature Based HiZ Detection Block Diagramvisualization. A 32kA test of the C5 CT.



a. Arcing Fault Response Procedures

As previously described, signature based HiZ algorithms can provide three different output designations, namely: arcing suspected (or intermittent arcing), arcing detected, and downed conductor. Each utility needs to establish standard responses to each of these outputs. At this stage in the implementation cycle, typical responses have been as outlined in Table 1.

If tripping of the feeder is chosen as a course of action, one of the ensuing challenges is locating the HiZ fault. While energized, the arcing fault / downed conductor can often be located via sight, sound, radio frequency interference (RFI), or loss of power in an area. Once the feeder is de-energized, all the above become non-functional. As such, the decision to de-energize or not to de-energize must be based on the relative consequences of each action. For example, if the region is around a school or residential area, there is a strong bias to de-energize. On the other hand, if the arcing line is feeding a hospital or an industrial region, the decision might be to alarm.

Condition	Primary Response	Secondary Response
Arcing Suspected	Alarm	-
Arcing Detected	Alarm	Trip
Downed Conductor	Trip	Alarm

Table 1
Typical Arcing Condition Responses

It is strongly recommended that any utility installing HiZ detection devices develop a written response procedure to each of the above HiZ conditions.

b. Line Grounding

The HiZ element was primarily designed for solidly grounded systems. The same algorithm has been tested with some degree of success on impedance grounded systems as well a few tests on ungrounded systems. The algorithm did pick up, however, consistency of operation was an issue. One other test performed involved a downed conductor opposite the source side of the line (see Figure 4). In this configuration, there was a down-stream transformer. When the transformer was loaded, detection of the downed conductor back in the substation was achieved.

c. CT Ratio

The ground current on a downed conductor may be only a few amperes on a feeder with several hundred amperes of load. Choosing as small a CT ratio as possible maximizes the arcing component in the waveform and optimizes the ability of the HiZ algorithms to detect the HiZ fault. The algorithm has been successfully tested with CT ratios on the order of 1200:5. The HiZ algorithm use standard relay accuracy CTs.

d. Sensitivity Vs. Security

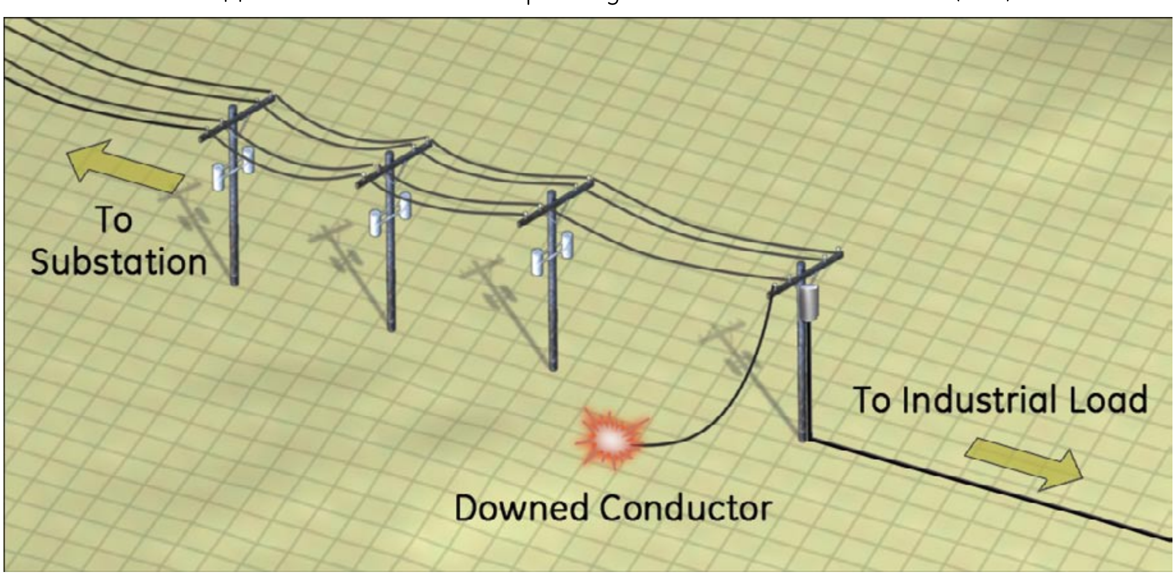
The major setting in a HiZ device is Arcing Sensitivity. HiZ detection is no different from any other protection scheme in that there is a trade-off between sensitivity and security. An algorithm can be designed to pick-up on almost any disturbance on the feeder. The challenge is being able to discriminate between events. The sensitivity setting represents a balance control between sensitivity and security. Security can be enhanced by requiring multiple detections of the arcing condition before a HiZ condition is declared.

Typical recommendations are for a balance of sensitivity and security in the normal operating mode. Under conditions such as an impending storm, it may be desirable to actually de-sensitize the algorithm, as with everything wet, there is usually much arcing leakage around the system. On the opposite extreme, if a region has been experiencing a dry spell, it may be desirable to set the sensitivity to maximum. In any event, remote control of setting groups to allow such changes is desirable.

e. Overcurrent Coordination

The general consensus for feeder fault protection is that, given there is sufficient current, to have the overcurrent element(s) operate and trip out the feeder before the HiZ element operates. This dictates the need for an overcurrent coordination timeout period. Setting of this coordination time should be based on the operating time of the time overcurrent (TOC) element for a

Fig.4.
Load Side Downed Conductor



fault located at the end of the feeder. The HiZ algorithm can operate in as little as 20 seconds whereas a TOC relay may take much longer to operate. Too long a coordination time (> 1 minute) is not recommended as HiZ faults tend to decrease in magnitude over time as the conductor “glasses over” and/or breaks – resulting in a smaller ground contact area.

A related application note on TOC relays is the need to coordinate not only the operate time, but also the reset time. On HiZ faults, a TOC element will “ratchet”, that is, move forward for a period of time and then begin to reset as the fault current drops below the pickup level of the relay. If a TOC relay with instantaneous reset is placed downstream of a TOC relay with timed reset, the relays may mis-coordinate resulting in the disconnection of more of the feeder than desired.

4. Experience to Date

To date, utilities around the world have installed over several hundred HiZ detection devices. Dozens of real arcing suspected, arcing detected, and downed-conductor events have been recorded with a number of the installations connected to trip. Almost all report into SCADA. The ratio of “detected” downed conductors to the total population of downed conductors has been about 80%. The following are a few highlights from the accumulated experience base:

• On the JEA Jacksonville, FL system, reports of “arcing suspected” were being received from a HiZ device at the same time every day for a period of time. Figure 5 shows “arc confidence”, integrated arcing information from the reporting IED. Note that the arc confidence rose quickly for two integration periods then settled out. As a result, the detection on this event was reported as “arcing suspected” initially and shortly after, “arcing detected” was declared. Inspection of the line uncovered no obvious arcing sites. Following this result, an analysis of the customer base connected to the suspect feeder was performed and one customer with a heavy-duty process was identified. A phone call to the identified customer was made to inquire if any of his processes included arc furnaces or other arcing loads to which the customer responded “no”. On the day following the inquiry by JEA, the customer phoned back and stated that a large motor in their facility had just failed. The HiZ device was able to see through the distribution transformer into the customer site and the customer motor.

The connection to the high voltage bushing of a distribution transformer had become loose and began to arc. The resulting signature was detected by a HiZ device (as well as the customer, when his lights went out once the connection burned through.)

• After a long dry spell, a rainstorm came into the area. Many of the insulators on the feeders, which had become quite contaminated, began to conduct in an arcing manner. In conjunction with the storm was lightning, which produced a transient fault on one of the feeders. As a result, the HiZ IED saw fault current followed by arcing and declared a “downed conductor”.

• Many utilities have performed staged fault tests on their systems in order to test the effectiveness of HiZ detection. In most cases, the utility would include a “challenge” test case – typically a conductor dropped on asphalt or sand. In this one test, the conductor was dropped on asphalt with the expectation of no detection. What occurred, however, was that the arc found paths through cracks in the asphalt that permitted arcing and subsequent detection by the HiZ device.

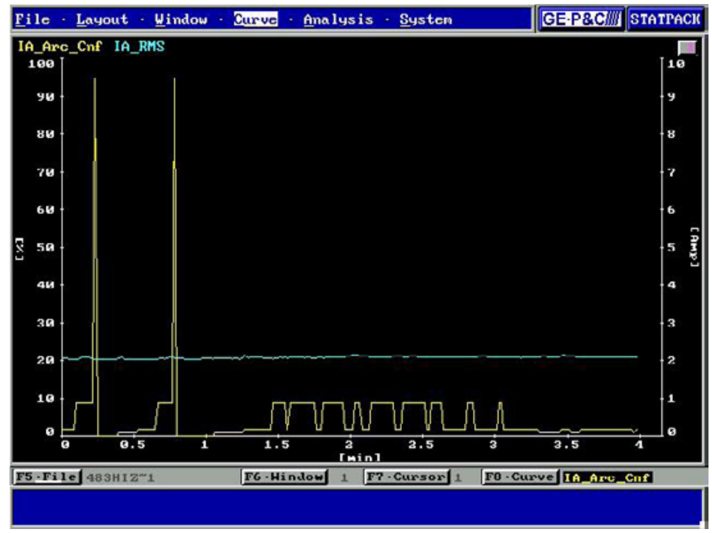


Fig. 5.
Arcing Signature for Failing Motor

• One question often asked is how “directional” is the HiZ algorithm? To find the answer to this question, one utility ran staged fault tests with HiZ IEDs installed on two parallel feeders (see Figure 6). HiZ faults were placed on one feeder while the performance of the parallel feeder was observed. In all cases, the HiZ IED on the non-faulted feeder did not detect any arcing, while the HiZ IED on the faulted line detected about 80% of the HiZ staged faults.

• As utilities expand their usage of HiZ devices, they are surprised by the number of arcing conditions existing on their distribution system. As JEA added HiZ signature devices to 27 feeders, it came as a total surprise that 50% of these feeders began to report “arcing suspected” conditions. Now that JEA knows that something is happening, they plan to use other devices to help locate/determine the root of the arcing conditions

• Finally, in the challenge arena, several HiZ faults were staged on dry sandy soil. In most cases, the HiZ IED did not detect arcing. Analysis of the waveforms from these faults does show a change in energy; however, sand does not exhibit the “randomness” of other material types.

5. Lessons Learned

As a result of the knowledge base garnered from several years of field experience, a number of enhancements to the HiZ algorithms have been identified.

a. Downed Conductor Misclassification

First and foremost has been the issue of mis-classification of an arcing fault as a downed conductor for a fault on a parallel feeder followed by arcing. The parallel feeder fault drops the voltage on the substation bus and assuming near unity power factor operation of the feeders, all feeders connected to the bus subsequently see a loss of load. If this loss of load is followed by arcing (as was the case with the contaminated insulators previously mentioned), the HiZ IED will declare a "downed conductor". A simple fix in the form of an under-voltage restraint was added to the loss of load logic. Now, if a loss of load occurs in conjunction with an undervoltage, the loss of load logic flag is not set.

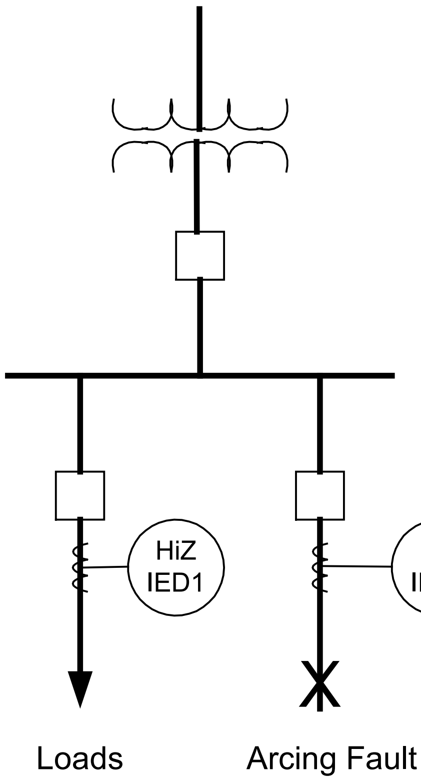


Fig. 6.
Paralleled Feeder Selectivity

b. Transformer Inrush Restraint

Although no reported cases exist, the inrush waveform resulting from the energization of a transformer can look like arcing. The inrush waveform, however, is very distinguishable as compared to arcing. In particular, inrush has a very high second harmonic component – much higher that that seen in arcing. Given this simple differentiator, an arcing restraint was added to the algorithm such that if the 2nd harmonic component of the waveform is greater that a percentage of the fundamental (a user setting – typically about 15%), the arcing detected algorithm is reset and block from operation.

c. Dynamic Energy Level Adjustment

In the course of field experience, it was clearly observed that not all feeders were created equal with regards to the steady state harmonic energy levels that existed. This variance required the setting of a minimum energy threshold significantly above what the energy levels on a typical feeder would be. In order to optimize the sensitivity for each individual installation, a "dynamic" energy threshold was added to the algorithm. In this mode of operation, the average harmonic energy level on a feeder is measured over a 3-day period. The harmonic energy thresholds are then set at a value of 3-sigma above the average energy value thereby allowing each feeder to operate at maximum sensitivity.

d. Oscillography and Sequence Of Events (SOE) Overrun

Arcing events tend to be bursty, that is, an event may pick-up for awhile, settle out, then pick up again. As IEDs try to log the activity, SOE and oscillography logs tend to overrun. Solutions to this problem are twofold: With regard to oscillography, the concept of priority was developed. All file types were assigned a priority and depending on the priority, it could over-write a file of lower priority. For example, a file created by a "downed conductor" event (highest priority) would be allowed to over-write either an "arcing detected" waveform file (medium priority) or an "arcing suspected" waveform file (low priority). With regard to SOE overrun, arcing events were latched for up to 10 minutes thereby allowing only one arcing event entry every 10 minutes – a significant reduction in the possible number of events that could be entered in the SOE log.

6. Future Directions

Given the HiZ detection experience to date, there are a number of areas where further investigation and research are desirable. This section highlight a few of these areas:

a. HiZ Fault Location

As mentioned earlier, once an arcing fault is detected, there is the challenge of locating the faulted circuit. A distance to fault calculation has often been talked about, but at this juncture, it is still some ways away. JEA is investigating using a corona camera (Figure 7) to aid in the fault location process.

The camera spectrally images the corona energy from the conductor and then superimposes the spectral energy onto the background object. The benefit of this technology is that it can be operated in direct sunlight.

Fig. 7.
Corona Camera

b. HiZ Directionality

As HiZ devices become more common in the distribution system, the need to coordinate arc direction on the same feeder becomes desirable. In particular, in the scenario of a main breaker and several down-stream reclosers, it would be desirable to be able to sectionalize the HiZ faulted section as is presently done for low impedance faults. Sectionalization could be optimized with the addition of recloser-to-recloser communication. Radio communication systems are readily available today that can provide the communication channel and UCA based relays already incorporate the ability to message among themselves.

c. Sand Settings

As noted in the paper, sandy soils do produce arcing energy, however, they do lack the randomness component. Future developments need to explore the possibility of creating a sand setting that focuses on the energy aspect of an arcing fault and de-emphasizes the randomness component.

d. HiZ Fault Type Determination

It is desirable to be able to determine the type of HiZ fault based on the signature of the energy waveforms. Ideally, the signature analysis would be able to identify not only an arcing conductor but also equipment trouble such as a contaminated insulator, a failing transformer or an arcing motor. Effort is needed to build the database of these disturbances to allow such discrimination.

Conclusions

HiZ Detection technology has taken major strides in the last several years and the knowledge and experience base surrounding it has grown dramatically. It is clear that as technology advances, so will our ability to do more with arcing waveforms including advanced sensitivity and detailed event type analysis. It has also become clear that utilities need to take a "system" approach to HiZ detection on their distribution system by taking advantage of all the mechanical and electrical HiZ detection devices offered by the industry.

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imagination at work

Design and Implementation Of Wide Area Special Protection Schemes

Vahid Madani, Mark Adamiak, Manish Thakur

Abstract - Power system protection brings to mind schemes designed to isolate faults in a given piece of equipment or line, either in the immediate area and/or in areas adjacent to the faulty system component. The size and complexity of the power grid, however, makes the electrical system vulnerable and subject to collapse under situations such as congestion, over/under frequency, over/under voltage, system load adjustment, power swings, etc.

To detect and take preventive/protective actions for these conditions, a class of protection schemes known as Special Protection Systems (SPS), also referred to as Remedial Action Schemes (RAS), are developed to address system wide operating conditions. A Special Protection System is typically different in concept and implementation from a conventional protection scheme/system in that the schemes are generally intended to provide a safety net for the electrical grid during unplanned contingency conditions or when system or operating constraints could not allow meeting the power demand.

Implementation of such schemes involve many factors including:

- Comprehensive knowledge of the wide area system to which the scheme will be applied
- Well-developed system planning criteria defining:
  - The intent - including whether thermal or stability limits apply
  - The undesired yet possible contingency conditions
  - The real-time monitoring parameters and arming conditions
  - The overall system performance criteria and the throughput timing based on system studies
- Detailed design and implementation for operation and restoration
- Reliable telecommunication system
- A well prepared set of operating and maintenance manuals along with visual aid tools
- Levels and types of redundancy
- Detailed test plans for scheduled system wide testing

This paper will discuss the drivers for implementing SPSs, the functional requirements of such systems including the interface and coordination with existing protection and control equipment, and the resulting design considerations such as system architecture, Human Machine Interface (HMI), communication system robustness, performance monitoring, and system test (including commissioning, manual, and automatic test modes).

1. Introduction

Blackout prevention / mitigation and power system security are the order of the day. Managing congestion, balancing load and on-line generation, maintaining spinning reserve capacity margins, and managing reactive power support through reliable real-time data are some of the key elements of successful power system operation.

Recent newsworthy wide-area electrical disturbances have raised many questions about the causes and cures for such occurrences and have demonstrated the vulnerability of the interconnected power system when operated outside its intended design limits. The exposure of the power system to wide area collapse has increased in recent years as the system has been pushed to its operating limits - often resulting in violation of NERC operating policies and planning standards [2][3].

One of the U.S. Department of Energy (DOE) and the Canadian Natural Resources (NRCAN)'s top priorities are modernizing North America's electricity infrastructure. This effort focuses, amongst others, on the application of technology to enhance the reliability and efficiency of the entire energy delivery system.

Electric reliability and efficiency are affected by four segments of the electricity value chain: generation, transmission, distribution, and end-use. Satisfactory system performance requires investments in all these segments of the system. Increasing supply without improving transmission and distribution infrastructure, for example, may actually lead to more serious reliability issues.

The Transmission Reliability Program is developing advanced technologies, including information technologies, software programs, and reliability/ analysis tools, to support grid reliability and efficient markets during this critical transition.

The National Transmission Grid Study [1] has made it clear that without dramatic improvements and upgrades over the next decade our nation's transmission system will fall short of the reliability standards our economy requires, and will result in higher costs to consumers.

The Transmission program's mission specifically is to develop technologies and policy options that will contribute to maintaining and enhancing the reliability of the nation's electric power delivery system during the transition to competitive power markets.

There are often many issues to address reliable system operation, however, the primary issue is typically the heavily loaded transmission system (with subsequent high reactive power losses/requirements). This overloading is often at the root of system instability problems. The understanding of this issue is not lost on legislators and regulatory bodies who have expressed their concerns about potential blackout scenarios. Reactive power flow analysis, including mitigation of voltage instability, should become an integral part of planning and operating studies and have been mandated in the recent NERC recommendations for prevention and mitigation of future NE blackout scenarios [2]

It should be noted that the issues faced, in many cases, are not easily overcome. Transmission owners are faced with challenges when placement of new generation is justified by factors such as market forces, permit availability, sighting opportunities, and strict environmental constraints as opposed to system studies. Under these scenarios, load centers often end up connected far from generation resources and through heavily loaded weak transmission systems. Subsequently, deregulation and the high cost of building new transmission infrastructures have placed the transmission owners under increasing pressure to maximize asset utilization. Transmission operators note that they have credible contingency situations that can result in voltage collapse or system instability challenges imposed by insufficient levels of reactive compensation. The potential risk of voltage instability, especially during contingent conditions has been evident without the continued dynamic reactive support.

2. Solution Space

As mentioned above, one of the issues to address is lack of reactive power sources. The North American Electric Reliability Council (NERC) Planning Standard specifies that:

> "Proper control of reactive power supply and provision of adequate reactive power supply reserve on the transmission system are required to maintain stability limits and reliable system performance. Entities should plan for coordinated use of voltage control equipment to maintain transmission voltages at reactive power margin at sufficient levels to ensure system stability with operating range of electrical equipment." [4]

Dynamic VAR support is often needed to maintain the desired operating voltage levels and mitigate voltage instability from unscheduled generation and transmission contingencies during high load conditions. As such, one piece of the solution space is addition of Var sources on the system. Some of the reactive compensation alternative includ

- Static VAR Compensator (SVC)
- Synchronous condensers
- Unified power flow monitoring and control
- Flexible AC Transmission Systems (FACTS)
- Switched shunt capacitors

In addition to reactive compensation, power flow regulation devices such as series capacitors, Thyristor Controlled Series Capacitors (TCSC), and DC lines can be installed on a system. In the total stability solution space, these technologies may be required, however, they tend to have long lead times and are capital intensive.

Advancements in the real time monitoring of power system parameters and availability of secure high-speed telecommunication networks now provide opportunities for implementing wide area protection and control schemes generically known as Special Protection Schemes. NERC defines SPS as:

> " — an automatic protection system (also known as a Remedial Action Scheme - RAS) designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows.

3. SPS Design Process

In this paper, the SPS design process is broken down into five steps, namely:

1. System Study
2. Solution Development
3. Design and Implementation
4. Commissioning / Periodic Testing
5. Training & Documentation

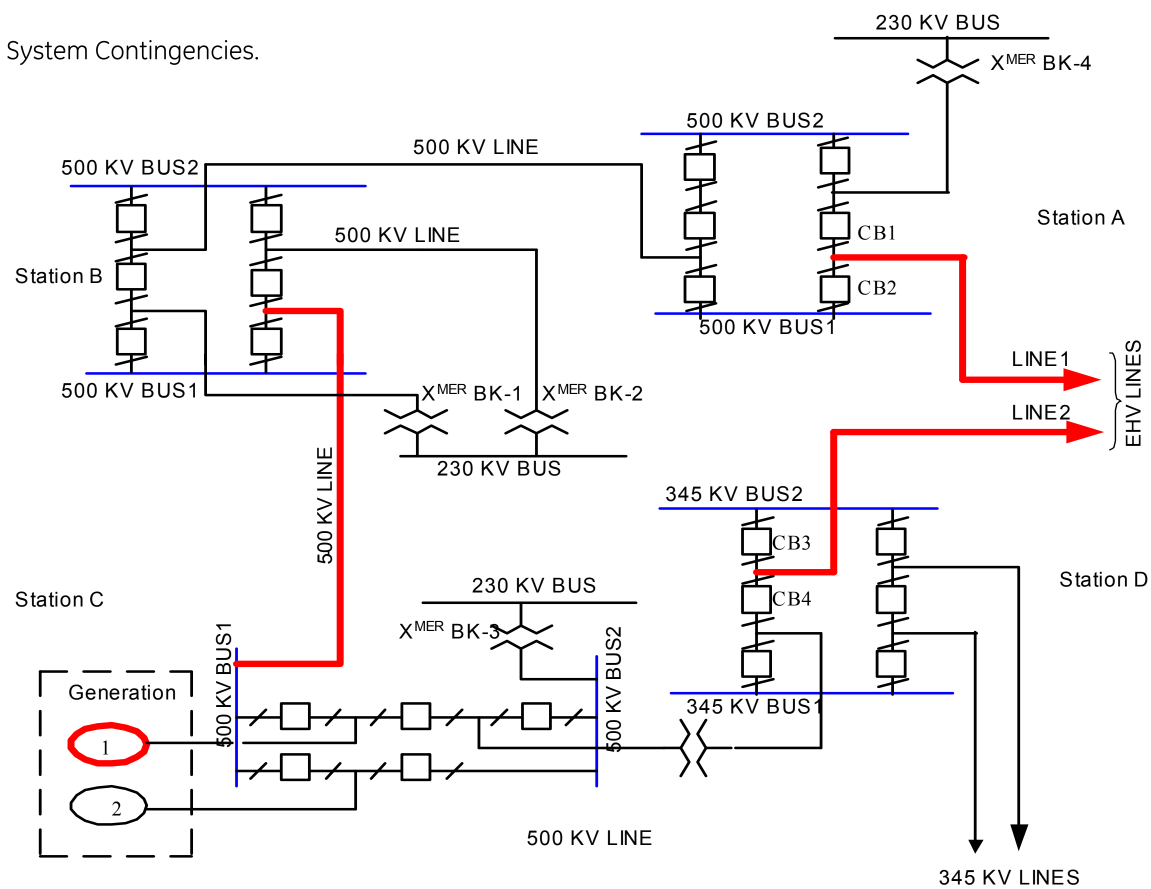
Items to be considered in each of these steps are described in the sections below.

3.1. System Study

In order to design a wide area monitoring and prevention scheme, accurate system studies need to be completed to identify the ensemble of contingency scenarios and to define the parameters required for proper implementation. Some of the critical items include:

- Understanding the requirements and the intent of the application – (different requirements result in different solutions)
- Types of studies to be performed – Planning and Operating studies, followed by on-going system studies including protection coordination studies
- Evaluating multiple solutions – Studying alternatives and performing contingency analysis
- On-going dialog with all entities involved – Internal and external (Regional).
- Identifying monitoring locations and set points – overload conditions, undervoltage, underfrequency, phasor measurement

Fig. 1.
One Set of Identified System Contingencies.



• Arming conditions and levels – Determining whether the scheme arming should be power system condition based or outage/contingency based
• Contingency identification
• Identify islanding points if applicable
• Voltage or phase angle stability
• System restoration process; Cold Load Pickup considerations [9].
• Wide area monitoring and intelligent dispatch
• Reliability and dependability levels – Redundancy, Voting, Fail safe, etc.

System studies identify limitations or restrictions. The limitations may be thermal, voltage, or angular instability related limits wherein the latter items are of significantly more concern than thermal capacity limits. It should be noted, however, that relaxing non-thermal limits in a cost-effective fashion can be very challenging in a deregulated environment.

3.2. Solution Development

Once the system studies are completed, the solution space must be analyzed and specific recommendations must be made. Figure 1 shows an example area that might have been modeled in a system study. The **Highlighted** items depict outages and/or overloads on particular pieces of equipment. Of note in this example is the fact that a generator outage in one area of the system coupled with the outage of one line in the "western" portion (near stations B and C) of the system and an overload on two other lines in the "eastern" portion (near stations A and B) of the system will create a potential voltage collapse or generation/load imbalance scenario.

Given the defined contingencies, a method of conveying the actions for a given contingency is required. One technique is to migrate the monitored quantities and subsequent state transitions in a flowchart. Figure 2 illustrates such a flow-chart for a situation where remedial action is required for a particular piece of equipment being out of service. Once the outage is detected, updated power flow measurements are used to determine whether any arming is needed. If the measured line flows are less than the value from the study (500MW in this example), stable system operation can be expected. However, when line flows exceed the limits identified by system studies, the system is automatically armed for a pre-calculated load-shed upon detection of the next defined contingency. In this example, the amount of load shed needed is compared against that available and then an optimal load-shed decision is selected.

3.3. Implementation Solutions

Once the design and application planning aspects of the SPS have been defined, many questions arise regarding the implementation such as:

• Identification of the functional and technical requirements (evaluation of monitoring, isolation of transmission equipment, breaker failure application, redundancy, etc.)

• Selection of the technology to meet the functional requirements of the SPS technically and economically, such as high speed secure communication between the SPS devices and programmable solutions to protect the system against severe contingencies
• Identification of the areas that may need new technology developments
• System diagnostics.
• Flexibility/Upgradeability to meet the future expansions or requirements of designed SPS
• Description of scheme operation and well prepared Maintenance plans / Intelligent or Automatic Maintenance Testing
• Communication system design and failure detection systems. For example, routing of primary system communication failure on the alternate communication medium when dual schemes are applied.
• Simplicity of the implemented solution over the life cycle of the project and as new operators, maintenance specialists, and engineers take responsibility for expansion or operation.
• Cost effectiveness for implementation.
• Provisions for alternate location for manual arming
• Breaker failure operation and automatic restoration – Should breaker failure be incorporated as part of the design and whether automatic restoration should be considered for parts of the scheme operation

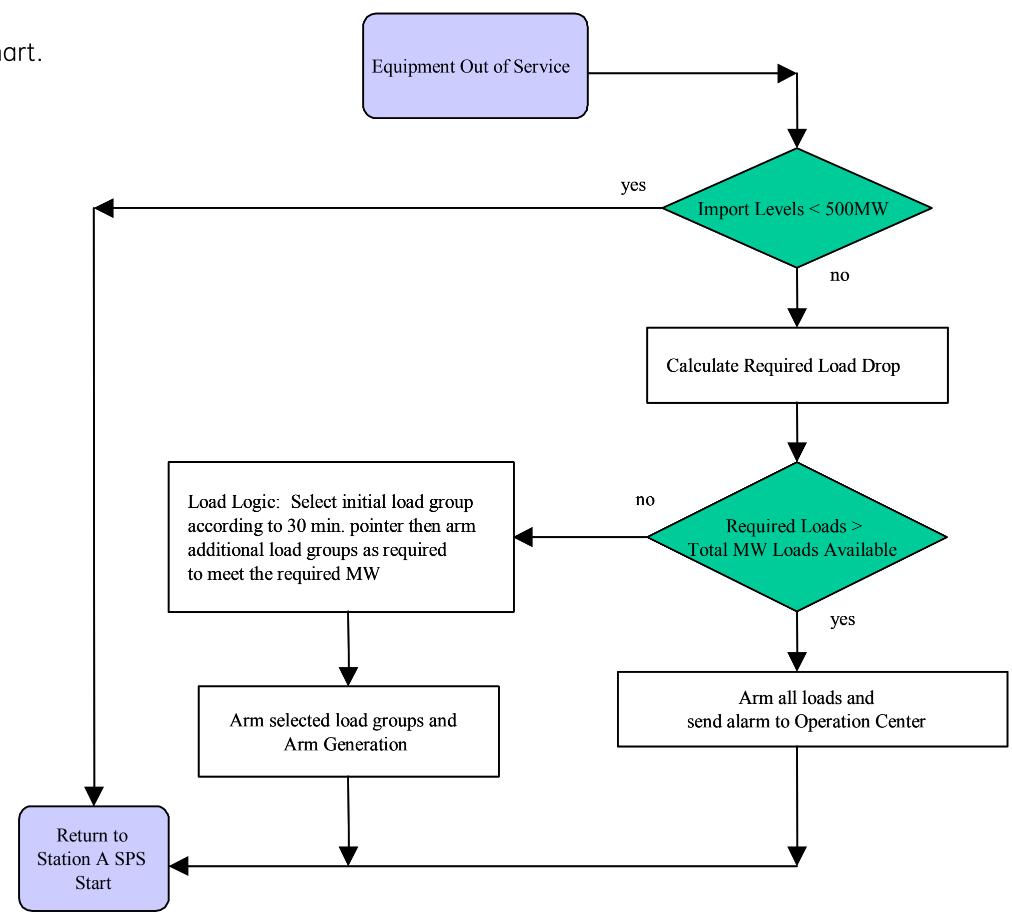
Knowledge of the answers to these questions bring us to the next steps of the implementation solutions, which are as follows:

○ Developing a test plan
○ Established procedures for continual or rotational training

Selection of equipment for such schemes should provide real time data to enable:

• Validation of contingency models to improve simulation and analysis of power system stability
• Advanced monitoring and warning indication as the power system approaches thermal limitations and / or system instability
• Flexibility to adapt to changes in power system conditions
• Expedited restoration coupled by recommended restoration alternatives [5]
• On-line operator or dispatch training opportunities for responsive and coordinated restoration; with cold load pickup considerations
• Accurate and timely analysis of disturbances
• Automated data gathering system for sequence of event listing based on absolute synchronized information
• Simplified data analysis to assist with investigations and root cause determination or faulty equipment performance
• On-line monitoring to provide both internal (IED failure) and external (communication failure) condition monitoring
• Device synchronization

Fig. 2.
Contingency Action Flow Chart.



The implementation solutions should also involve the following steps:

- Identification of the project team including manufacturers where needed
- Equipment selection and application process that would involve various groups responsible for the maintenance and operation of the system
- Implementation of automated and intelligent system testing as well as a well developed test plans for such system-wide tests

The selection and application process will assist the project team to identify the functional and technical requirements of the SPS such as the location of system controllers, monitoring points, the transmission equipment to isolate for various contingency conditions, methods of compensation for the deficiency in a given network, typical Protection and Control functions, type, speed, and security of communication options, communication broadcast options to share significant information such as telemetry, status, maintenance switching, and outage information with considerations for network congestions. The key focus here is to choose the right technology followed by proper implementation.

Another significant factor is different practices and familiarity amongst maintenance and engineering personnel in different companies with different types of equipment and communication interfaces. Established maintenance priority agreements are recommended - different systems or entities may have different maintenance priorities

3.3.1 Functional Evaluations

The intention of this step is to look into the detailed functional requirements such as number of monitored transmission / distribution equipment points, bus configurations, selection of secure communications, automatic restoration provisions, inputs / outputs, programming needs, throughput timing considerations, etc.

In the implementation, a separation of tradition protection and control devices and SPS devices is recommended. Reasons for maintaining such separation include:

- Different maintenance and operating needs and failure response times for the two types of applications
- Need for different set points and the types of setting elements used for conventional protection vs. those needed for SPS applications
- Device setting changes and potential impact to other schemes
- Different clearance requirements
- Availability of the SPS devices for routine automated system testing (Isolation or unavailability of the SPS devices may not cause system limitations while may not be acceptable from the equipment protection prospective)
- Need for different test and isolation points
- Potential confusion from operating and maintenance prospective
- Communication network, interfaces, and routing are different between SPS devices and those used for conventional equipment protection

Ultimately, each application would need to be evaluated on a case-by-case basis. The complexity of the scheme, its purpose, space availability, and other factors may drive some of these decisions. Ultimately, the pluses and minuses of each option must be quantified in order to make the optimal decision. It is recommended that the cost of the project be evaluated over its total life cycle (which includes ease of test and maintenance).

3.3.2 Technology Evaluation

Evaluation alternatives should involve in-depth knowledge of the existing practices, operating constraints, and Regional, Provincial, or Governmental Reliability requirements, and cost effectiveness of the solutions. When the technology does not meet the functional requirements of the SPS such as reliable out of step detection methods, load shedding, islanding, restoration, etc. in the best possible ways, then look for opportunities to develop solutions to fulfill the requirements, or present the challenge to manufacturers for developing the technology.

Another key component of technology evaluation is field upgradeability. Considering the future changes in the generation and transmission network of the power system, it is expected that the SPS schemes will require modification over their installed life. Upgradeability should be evaluated from both a hardware and software perspective.

3.3.3 Communication Options and Algorithms

One of the vital elements of SPS or RAS design is a reliable and secure communication infrastructure for data exchange amongst monitoring and controlling devices. These devices are often required to send, receive, filter and process status and / or analog measurements.

Some SPS communication requirements/solutions include the following:

- Communication architecture to support redundancy and data integrity
- Sufficient bandwidth to meet the communication time constraints
- Communication system diagnostics/alarms

Standards that meet the requirements include:

- IEEE C37.94 (N x 64 kbps communication)
- IEC-61850 for Peer-to-peer communications interfaces (10/100MB Ethernet based)

3.3.4 Complexity Vs Simplicity

In general, the wide area special protection scheme implementation is a multi-disciplinary process involving experts in automation, telecommunication, planning, operations, protection, and maintenance.

The selection of various equipment needed to implement such schemes, identification of monitoring points, types of alarms and priority classification, various contingencies associated with equipment abnormal conditions, types and availability of real time data, considerations for various categories of inputs and output tests, development of the test scenarios, coupled by provisions for automated testing make such schemes very complex. Furthermore, wide area protection schemes may involve many different entities with different background and practices.

It is therefore paramount to make application of such systems user friendly, and the functional performance relatively easy to understand, as equipment selection and application are considered and as the design phase progresses. Such applications are intended to perform for unlikely events and thus may not be exercised as frequently as some of the conventional equipment protection schemes.

3.3.5 Communication System

Considering the significance of the information passed over the communication channels, a robust communication channel is required. Today's technology allows robust communication network which offer:

- Low error-rate communication channel
- Low latency
- High Availability
- High security
- Deterministic

Low error rate communications can be achieved through fiber channels or low-noise copper channels. At a minimum, a copper communication channel with a Bit Error Rate (BER) of less that 10^{-4} is required. With a BER of 10^{-4} and a communication pack size of 200 bits, the probability of a lost packet is 1 out of 50. The probability of getting two bad packets in a row is 1/2500 that would delay operation of the system by 16ms.

More important than low noise is high data security, that is, if there is an error in a packet of data, the device must have a high probability of being able to detect bit errors in the message. This function is typically accomplished through the addition of a Cyclical Redundancy Code (CRC) – an error detecting methodology - along with the message. The probability of the CRC to detect an error is a function of its size. A 16-bit CRC is capable of detecting all bit error combinations up to 4 bits.

Although the probability of getting 5 errors in one message at a bit error rate of 10^{-4} is about once every 200 years, the real issue is related to burst errors. A burst error is when many bits (more than 6) are changed due to some event on the communication system. With a 16-bit CRC, the probability of NOT detecting a burst error is 1 out of 65,536. Although these are good odds, the communication industry tends to err on the conservative side and pushes the size of the CRC to 32 bits. With a 32-bit CRC (as used on all Ethernet communications), the probability of NOT detecting a burst error is 1 out of 4,294,967,296 – somewhat better odds.

Desirable in a communication system is the ability to monitor not only lost packets but also the rate of lost packets. When high rate of errors are detected, maintenance crews can quickly be dispatched to search out the source of the communication errors. In conjunction with error detection is the need to detect lost communications in general. The end users could also benefit from cost effective test tools that would help validate noise / error detection and system response during lab and commission testing.

Another desirable feature is the ability of the communication link to provide end to end timing – that is, how long it takes a message to travel from "Station A" to "Station B". Detection of communication delays outside the expected ranges again allows for quick crew dispatch, identification, and solution of the problem.

3.3.6 Restoration

As application of wide area monitoring often involves extreme contingencies, such schemes are not expected to operate frequently. Therefore, significant importance should be placed on effective and fast power system restoration after major disturbances Power system restoration needs to be executed with well-defined procedures that require overall coordination within the restoring area, as well as with the neighboring electrical networks [5].

Intelligent restoration recommendations could also be provided to the operating personnel as the frequency and/or voltage recover.

3.3.7 Central Controller

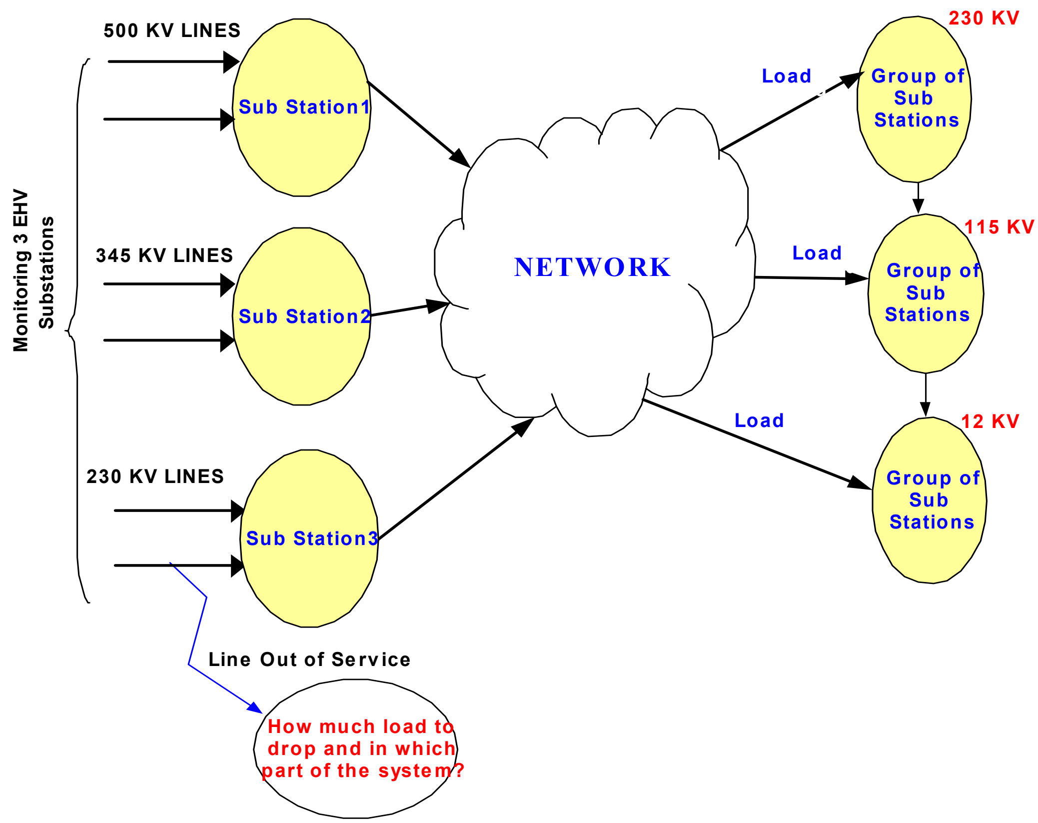
In many SPS applications, a Central Controller may be utilized. The expected performance may require the controller to consist of multiple parallel busses running in tandem with status and telemetry information exchanges taking place amongst the parallel processing busses. The controller design may also allow for "hit swapping" in case of component failures, also referred to as triple redundant controllers. The specification of the system controller should factor the overall functionality of the scheme.

3.3.8 Overall Functionality

The overall functionality of the scheme depends on the successful operation of various components either at the substation level or at the Central Control and Monitoring stations.

The overall functionality of the SPSs should be validated against the system studies. The total throughput of the system

Fig. 3.
Logical Architecture Design.



during commissioning and scenario testing stages, should measure significantly less than the throughput time identified in systems studies to allow for system changes and in case other stringent contingencies are identified in the future.

3.3.9 Logical Architecture

Given the various pieces of the solution, a next step is the development of the logical architecture. The logical architecture allows the designer to depict the data flows and logic locations of the complete system. This then helps the designer in the identification of gaps and seams in the design. Figure 3 shows a logical architecture for a three substation monitoring arrangement for an EHV system with the logical grouping of substation data as is required in the performance of the SPS logic (shown on the right hand side). Also shown is base `logic asking questions about line loss and possible resultant actions.

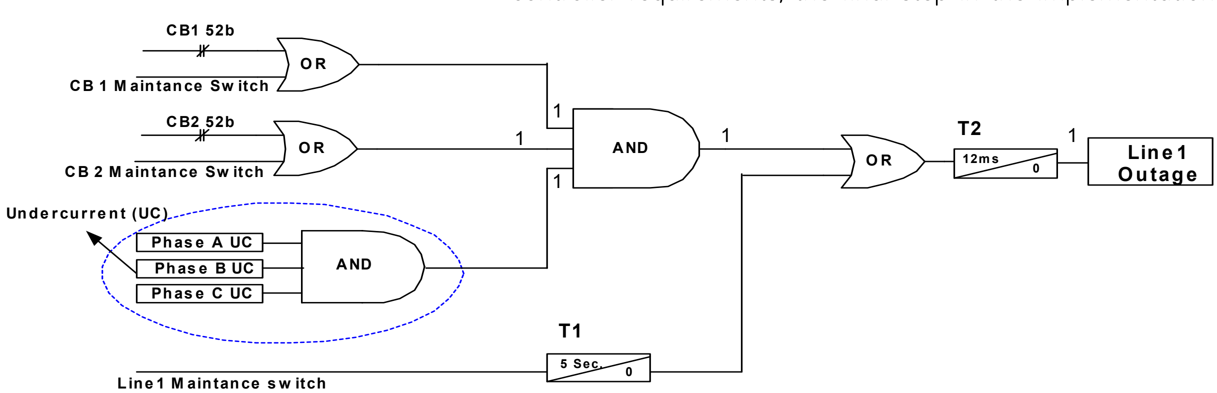
3.3.10 Logic Development

The next step in the process is the specific logic development. Depending on the solution determined by the system studies, the specific logic needs to be developed. In the example shown in figure 4, logic is shown for line outage detection logic for the 500 KV Line 1 shown in Figure 1 (breaker and half arrangement). The function is defined as a combination of undercurrent (UC) detection on all 3 phases of Line 1 and the breaker open condition (CB1 and CB2), or breaker maintenance switch set. In addition to this, The Line 1 maintenance switch can also create a line outage condition. An appropriate time delay (T2) can be applied to this logic, which avoids the rare but possible DC surge situation causing fictitious Line Outage.

3.3.11 Physical Architecture

Having done the engineering analysis as to the device inputs and outputs, communication requirements, and system controller requirements, the final step in the implementation

Fig. 4.
Line Outage Logic Example.



process is the development of the physical architecture. This drawing shows the number of devices required per substation, I/O requirements, communication channels and redundancy, system and device redundancies, time synchronization, controller locations, HMI facilities, etc. This physical architecture allows for one final review before sending the system out for final design. In addition, the physical architecture provides a mechanism for future explanation and operator training.

3.4. Testing

The ultimate success of the implementation solution depends on a proper testing plan. A proper test plan should include the lab testing, field-testing, study validation, and automatic and manual periodic testing.

3.4.1 Lab testing

Lab testing is designed to validate the overall scheme in a controlled environment. Lab tests permit controlled inputs from numerous sources with frequent checks of the output at every stage of the testing process. The lab tests ensure that the desired results are accomplished in the lab environment in contrast to costly and time-consuming field debugging.

For example, in a group of three SPS devices, a lab test could be simulated to check wide area communications (fiber/copper), average message delivery and return time, unreturned messages count and CRC failure count (under simulated noise conditions), and back-up communication switching timings.

It is advisable to create a detailed test plan as part of the overall implementation. A combination of the Logical Architecture, Logic Design, and the Physical Architecture could be used in preparation of the test plan.

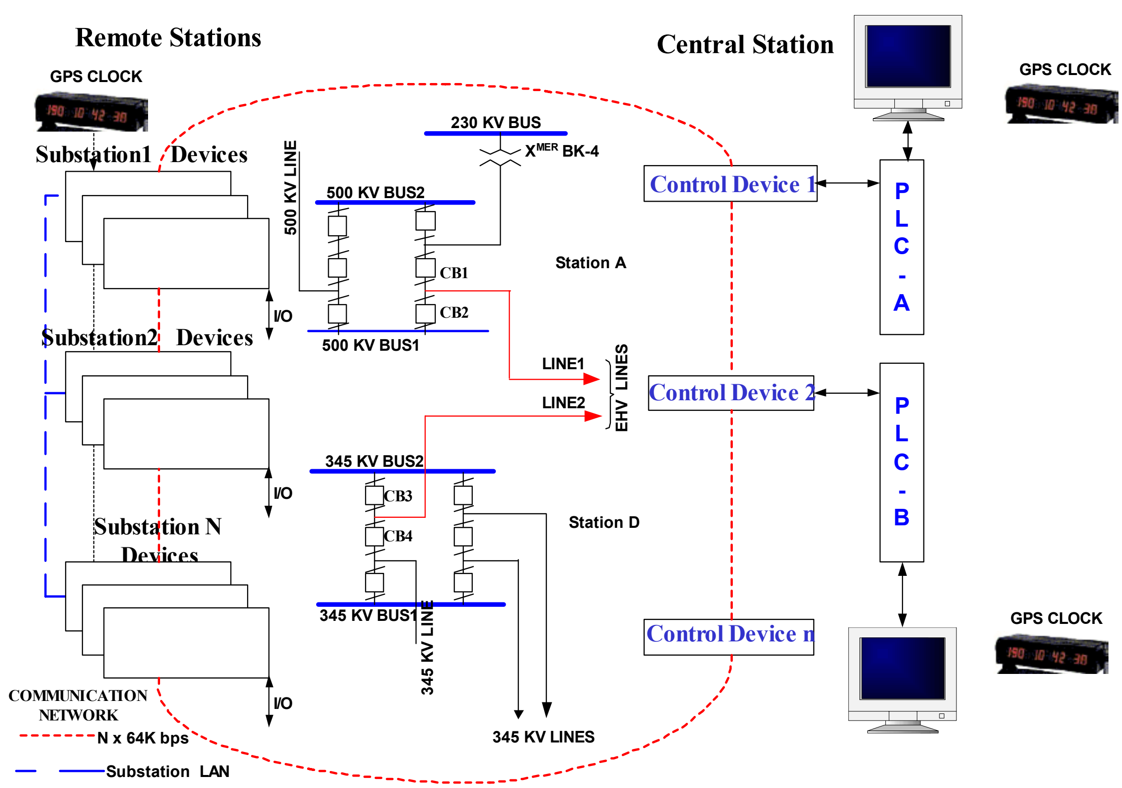
3.4.2 Field Commissioning Tests

Field commissioning tests should be carried out to check the performance of the special protection scheme against the real world abnormal system conditions. The telemetry data and the dynamics of various power system configurations such as breaker close and bypass contacts, changing the selectivity of the current transformer inputs, the total trip timing over the implemented communications between devices and the central control station, and the possible scenarios of unavailability of devices at the time of execution of a command signal in a given station all need to be tested. In general, every input point and every logic condition needs to be validated against expected results. Additionally, the effect of DC transients on Line Outage need to be tested thoroughly in the field before putting the scheme into service.

3.4.3 Validation through State Estimation

A critical consideration in implementing wide area monitoring and control schemes is the development of automated test scenarios. Such test cases could be prepared based on the type and the intended application of the scheme, and should

Fig. 5.
Physical Architecture



include provisions for ease of updating case studies as system conditions change.

For schemes that involve transmission constraints and stability limits, data from the state estimator can be used to determine different pre-outage flows within the power grid. The pre-outage flows are loaded into the controller as pre-contingency conditions. The controller, or simulator portion of the controller, would then be programmed for various outage, underfrequency, and / or undervoltage status scenarios to perform overall system performance evaluation.

State Estimator data could also be used to develop case scenarios representing future flows and load patterns for further system performance evaluations or to make adjustments where necessary.

3.4.4 Periodic Testing (Input/Output)

A proper test plan to simulate line outage on the monitored transmission/distribution lines in the respective substations and tripping of the lines should be conducted on a periodic basis to test the contingency plans and as a learning curve for the better understanding of the SPS

This test should be conducted without stopping any inputs – only actual trip outputs. For example, while simulating, a line outage, the monitored station should generate a trip output for the required load shed. The overall design need to incorporate the capability of isolating the trip signal but yet validating that it was issues. Devices such as latching and lockout relays can be installed for this purpose.

3.5. Training and documentation

The long-term effectiveness of an SPS design depends on how well it is understood by the operating and maintenance staff. The key point here is that proper documentation and training of SPS allows for its functionality to be easily assimilated by anyone. Training avoids human errors and also provides for ongoing feedback for improvement of the SPS.

4. Future Trends

As power system loading continues to outstrip transmission development, more complex system contingencies will develop and need to be addresses. The utility industry, however, is not standing still waiting for these next generation issues to suddenly appear. There are several trends on the horizon – some nearer, some farther out – that will facilitate next generation SPS design. A few of these trends are highlighted herein:

4.1. Emergence of IEC 61850

IEC 61850 – Communication Networks and Systems in Substations – is the next generation IED communication protocol. The protocol is defined on an Ethernet backbone and, as such, provides for very high-speed device-to-device communication. In particular, the standard implements out relatively new Ethernet functions such as priority and Virtual LAN allowing for more deterministic Ethernet packet delivery.

On the relay-to-relay communication front, IEC 61850 defines a Generic Object Oriented Substation Event message that enables the high-speed transmission of analog data messages from one to multiple other devices in the 5ms to 10ms time frame. Given this analog data transfer capability, IEDs will evolve to provide mathematical manipulation functions which will enable the ability of SPS designs to adapt and track historical performance. Logics could then be created to allow adjustments to support system changes as well as to support more precise future performance alternatives.

4.2. High-Speed Utility Intranet Availability

The available and continued installation of fiber throughout the utility enterprise has created, in many instances, wide area high-speed communication paths. Synchronous Optical NETwork (SONET) communication systems are providing 10 and 100 MB Ethernet options on a system wide basis. End to end delivery of Ethernet data packets has been demonstrated in as little as 6ms over a 100mi path.

4.3. Synchronized Phasor Measurement

Synchronized Phasor measurement or Synchrophasor is the simultaneous measurement of the magnitude and phase angle of the positive sequence voltage at multiple points around the electric power grid. Although the technology was defined in the early 1980's, the general availability of Phasor Measurement Units (PMUs) has only recently occurred. Phasor data has proven to be extremely useful in post mortem analysis of system transient events and is now being used to assist state estimation and Power System Stabilization (PSS) systems [6].

4.4. Wide Area Control Systems

Given the high-speed observability of the power system, a new class of power system control functions is being developed which are generally known as Wide Area Control Systems. The basic concept is that if one can observe the dynamic state of the power system, real time control actions can be implemented that, upon detection of a transient condition, can drive the system to a stable state. Application explored to date include state measurement (in contrast to state estimation), on-line voltage security [7], inter-area oscillation damping, system-wide voltage regulation [6], and real-time security control.

4.5. Real-Time Pricing / Direct Load Control

Lastly, a major initiative among many utilities throughout the world is the implementation of Real Time Pricing (RTP) and Direct Load Control (DLC). The recent industry deregulation on supply pricing can, under numerous conditions, result is very high prices for the supply of electricity. RTP enables the utility to directly pass the cost of electricity onto the customer and let the customer choose how much electricity he/she wants to use at a given price.

In the migration path to RTP, communication to the end-users facility will be required. This communication path will enable DLC. By coupling the DLC path with Wide Area Control, real-time closed loop control systems become realizable.

5. Conclusions

It is apparent that the present trend of load growth outstripping transmission will continue for the foreseeable future. In order to maintain power system stability over the ensemble of contingencies introduced by this load/transmission imbalance, protection engineers are challenged to find alternative solutions such as SPS / RAS to fill the gaps. A set of technologies exist to meet the needs for today and developments are progressing that promise to bring more sophisticated tools to affect better control over the massive machine known as the Electric Power Grid.

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IEC 61850

A Practical Application Primer for Protection Engineers

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1. What IEC 61850 is, and what it is not

Substations designed in the past made use of protection and control schemes implemented with single-function, electromechanical or static devices and hard-wired relay logic. SCADA functions were centralized and limited to monitoring of circuit loadings, bus voltages, aggregated alarms, control of circuit breakers and tap changers, etc. Disturbance recording and sequence-of-event data if available was centralized and local to the substation.

With the advent of microprocessor-based multi-function Intelligent Electronic Devices (IEDs) came the opportunity to move more functionality into fewer devices; resulting in simpler designs with reduced wiring. In addition, owing to communication capabilities of the IEDs more information could be made remotely available; translating into fewer visits to the substation.

Microprocessor-based protection solutions have been successful because they offered substantial cost savings while fitting very well into pre-existing frameworks of relay application. A modern microprocessor-based IED replaces an entire panel of electro-mechanical relays with external wiring intact, and internal dc wiring replaced by integrated relay logic. Users retained total control over the degree of integration of various functions, while interoperability with the existing environment (instrument transformers, other relays, control switches, etc.) has been maintained using traditional hard-wired connections. Distributed functions are rare, and restricted mainly to the SCADA realm.

In terms of SCADA integration, the first generation of such systems achieved moderate success especially in cases where the end-user could lock into a solution from a single vendor. Integrating systems made up of IEDs from multiple vendors invariably led to interoperability issues on the SCADA side. Integration solutions tended to be customized. Owners of such systems were faced with long-term support and maintenance issues. During this period two leading protocols emerged: DNP 3.0 and IEC 60870.

Beginning in the early 1990s, initiatives were undertaken to develop a communications architecture that would facilitate the design of systems for protection, control, monitoring, and diagnostics in the substation. The primary goals were to simplify development of these multi-vendor substation automation systems and to achieve higher levels of integration reducing even further the amount of engineering and wiring required. These initiatives have culminated in the release of EPRI-sponsored Utility Communications Architecture, or UCA, specification, a precursor of the 61850 international standard. After decades of competing protocols and integration challenges, 61850 was created by an International Electrotechnical Commission working group consisting of vendors, utilities, and consultants who were focused on the development of a standard in which devices from all vendors could be connected together to share data, services, and functions.

The vision of 61850 is extremely broad. While starting with a next generation SCADA protocol, the concept encourages and facilitates advanced applications in protection and control, to the extent of blending in non-conventional CTs and VTs into the overall scheme by providing for a standardized way of exchanging information digitally between the producers and recipients of this information. The “61850” phrase became a designator for the next generation substation system with a higher degree of integration, reduced cost, greater flexibility, communication networks replacing hard-wired connections, plug-and-play functionality, reduced construction and commissioning time, and other advantages. While many of these benefits are delivered by the SCADA part of the 61850 alone, there is an expectation that the other visionary elements of the package are also mandatory and ready for extensive deployment.

The 61850 Standard makes extensive use of the concept of virtualization. Data that is produced by IEDs is presented in a standardized format. In this way IED functions become generic from the point of view of the system designer but the underlying functions retain vendor specific characteristics that may be unique and proprietary in nature. The available data is also logically partitioned according to groupings that should be familiar to relay and SCADA engineers (protection, metering, supervisory control, etc.). The data is “self describing” in nature, obviating the need for memory maps and allowing the integrator to “browse” a device for the needed data. Presented data have attributes that are common across vendor platforms.

Additionally, the 61850 series standardizes the mechanisms by which data is accessed and exchanged within the substation. The IEC 61850 concept standardizes SCADA data and services, as well as encourages peer-to-peer exchange of information between the IEDs: Included are mechanisms for reporting and logging of information, mechanisms for passing critical messages such as tripping signals between devices, and mechanisms for transfer of voltage and current samples from process-level devices (microprocessor-based CTs & VTs) to protection devices. The design of automation functions requires a considerable amount of configuration of the constituent IEDs. Currently, when building multi-vendor automation systems, the designer is confronted with one or more configuration tools from each vendor. The 61850 series addresses this by defining a description language for substation configuration (Substation

Configuration Language, SCL). SCL permits the development of tools that can be used to describe the substation at a high level (single line diagram). These tools are also envisioned to configure reports/logs, control commands, critical peer-to-peer messages and sampled analog values. Vendor specific configuration tools must interface with system level tools using standard SCL files.

While the 61850 series facilitates the implementation of functions (protection schemes, control schemes, etc.) that are distributed amongst several IEDs (possibly from different vendors), the specification does not attempt to standardize the functions themselves in any detail. It is left to the end user to impose his or her own engineering practices and philosophies to the particular application. Correspondingly, the 61850 Standard makes few requirements as to which data models and data items are to be made available in a particular IED. The allocation of data models as well as much of the data that makes up the models is left to the IED vendor. This creates a potential disconnect between the vendor and the end-user. It is therefore critical for the system designer to carefully check specifications when selecting IEDs.

Similarly, the 61850 Standard details the attributes of the data exchanged between devices. These attributes include information on the quality of the data and information on the operating state of the source of the data (for example, normal versus test). Decisions on the response of a function that is presented with degraded data are outside the scope of the Standard. Additionally, the Standard permits the configuration of timing priorities for messages passed between devices. It is, for the most part, left to the designer to determine what level of priority is required for the application.

The Standard defines the description language (SCL) to be used by configuration tools, while the functionality of the tools themselves is outside the scope of the Standard. More importantly the overall engineering processes are not defined and are likely to be different than those of the past. Much of the IED settings will remain in the domain of the manufacturer specific IED configuration tool. There will (at least initially) be some conflicts created. Undoubtedly, engineering processes and the corresponding configuration tools will have to evolve in unison.

The IEC standard itself does not offer any particular system architecture to follow. Instead it describes several building blocks with the hope they will fit the future architecture while the latter is conceived. This is not a significant issue for functions integrated between SCADA and IEDs, but presents an obstacle for functions executed between IEDs and their remote inputs and outputs.

Some of the functions that have been implemented in the past will map easily into the IEC 61850 domain. Others will not. In some cases, long-held, underlying principles of system protection will have to be re-examined.

This paper seeks to identify significant issues arising as deployment moves forward, presents possible solutions in some cases and gives direction for further investigation in others.

2. Industry Trends and Expectations

Today's utilities are under considerable cost pressure. In the realm of protection and control, modern microprocessor-based multi-function devices offer great savings by simplifying panel design, eliminating a number of traditionally installed devices and associated wiring, eliminating RTUs, and simplifying substation SCADA systems.

The cost of a device providing a complete set of Protection and Control (P&C) functions for a given zone of protection has dropped dramatically in the last two decades. Nonetheless, the cost of a finished installed panel with primary and backup protection and independent breaker fail / autoreclose relay still remains in the 50 to100 thousand dollar range. It is clear that vast majority of this cost is associated with engineering and field labor, and not with the cost of the raw material.

On the other hand, shortages and aging of the experienced workforce coupled with a lack of inflow of new graduates, will create a large-scale problem in the 5 to 10 year horizon. This is within the time perspective of today's utility managers who started to realize that the retrofit schedules driven by the age of the secondary equipment, availability of experienced engineering staff, and the expected cost of retrofits and new projects do not converge.

With reserve margins low in many regions of the globe, outages required to complete retrofits or integrate a new substation, are already, and will remain, difficult to obtain. There is a growing need and expectation of a substantial reduction in the duration of P&C projects.

This need has sparked discussions around new next generation P&C solutions that would reduce the engineering costs, cut the field labor, and shorten the required outage time. Many utilities have decided to set up task forces with the mandate to evaluate existing technologies and trends and to work out more efficient ways of engineering P&C systems. Quite often, the above trends and expectations are labeled "61850". In reality the IEC 61850 implies one of possible solutions by providing set of standardized building blocks, with the hope the blocks will fit the future P&C architecture.

Means to achieve the benefits of the next generation P&C system include eliminating RTUs and associated wiring in favor of using only protection IEDs as interfaces with the primary equipment, standardizing P&C designs for better re-usability, deploying pre-assembled and pre-tested drop-in control houses, simplifying designs by migrating auxiliary devices such as control switches, annunciation, metering and other functions into protection IEDs, replacing stand-alone Digital Fault Recorders (DFRs) and Sequence of Events (SOEs) recorders with distributed records collected from protection IEDs, migrating all substation communication into a single media of Ethernet, etc. This alone allows for substantial cost savings and is being successfully implemented by many utilities using modern IEDs and existing SCADA protocols for integration and automation.

It seems, however, that under the cost and manpower pressure, the industry is getting ready for more aggressive steps beyond what is being done today by forward-looking utilities. Replacement of switchyard wiring with plug-and-play fiber-based solutions, replacement of inter-IED wiring including critical protection signaling with peer-to-peer communications, real-time sharing of processed analog signals between IEDs for further elimination of the hardware that interfaces with the primary equipment are discussed.

Substantial cost is associated with copper wiring ($10/point, 100 points on an average panel, tens to hundreds of meters of control cables per panel). Given the bandwidth of fiber-based signaling, the potential for plug-and-play assembly of fiber-based architectures, and much lower cost of fiber versus copper on the per signal basis, the next generation P&C solution is often viewed as eliminating "copper" and replacing it with "fiber". At the same time, fiber technology has been constantly advancing; driven by high volume applications in both the consumer (e.g. cable TV, Internet, telecom) and industrial (e.g. transportation, factory floor automation) markets. Deploying fiber-based networks no longer requires pioneering approaches, unique skill sets, or expensive, specialized equipment. Instead, off-the-shelf relatively mature solutions have emerged for laying out, patching, and terminating fiber cables. Overall the fiber technology seems to have enough momentum to grow into mission-critical applications including the outdoor high-voltage substation environment.

Considerable cost is perceived to be associated with integration of various devices for automation and SCADA purposes. Savings are expected by migrating to a better, "next generation" protocol compared with the existing DNP 3.0 and IEC 60870. Major areas of improvement that have been identified include object orientation (organization of data), self-description of data, using single high-speed communication media (Ethernet), and better station-level configuration tools. The leading protocols widely used today recognize the need for improvement and continue to evolve. For example, DNP can be used over Ethernet; and work is under way to incorporate some form of self-description into DNP.

The economic expectation derived from industry convergence on a single global protocol is high, regardless as to how this protocol compares with the existing multitude of protocols. All major vendors tend to operate globally these days. Opportunity to support just one substation protocol would allow them to focus better and invest more effort in a single standard solution.

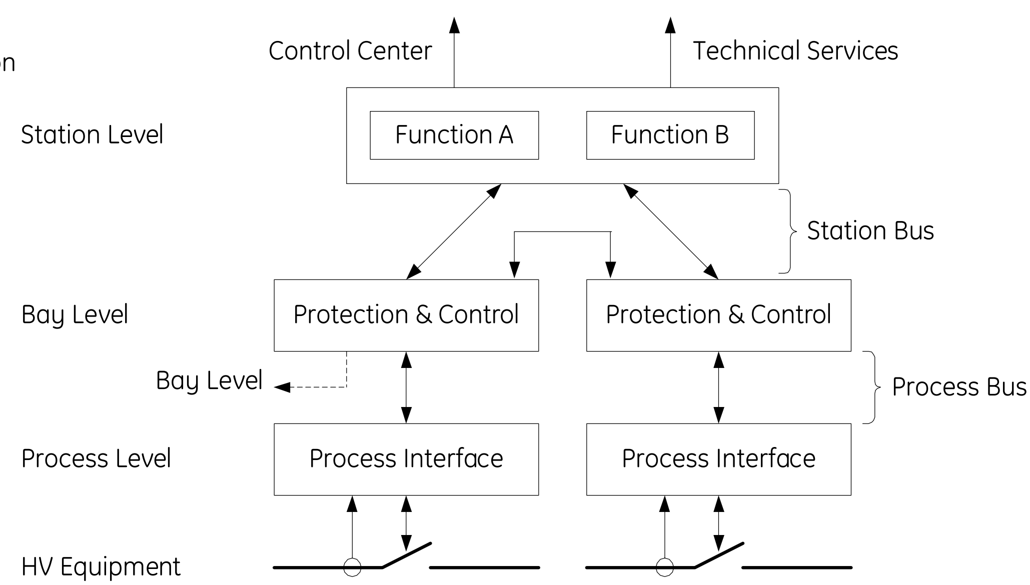
The IEC 61850 is viewed as the single answer to the above expectations and emerging trends.

3. The Vision of IEC 61850

In the beginning, the vision of IEC61850 was to define an interoperable communication system for the exchange of information between devices within a substation. Figure 1 shows the interfaces originally identified to be within scope of the Standard, specifically, process measurement (e.g. – voltages, currents, status) to device, device to station level, device to device, and device to Technical Services. Each interface brought with it different requirements for performance, Quality of Service, and reliability. Identified but not yet implemented interfaces are the Station Level to Control Center and Local Device to Remote Device (other substation) communication.

The structure chosen to implement this system was the International Standards Organization's 7-layer communication model. Specifically, the goal was to populate each of the layers, when needed, with existing standards that met the identified functional requirements. It was recognized that different communication profiles would be needed for the various communication paths that existed between devices. The primary protocols chosen for the various layers include Ethernet, the Internet Protocol (IP), the Transmission Control Protocol (TCP),

Fig. 1.
IEC 61850 Substation Automation Interface Model.



and the Manufacturing Messaging Specification (MMS). The various profiles actually defined by IEC61850 are shown in Figure 2. Note that the device to station level link which does not have specific performance requirements, uses a traditional TCP/IP transport and network layer whereas the device to device profiles, which requires fast (<4ms) communication, uses direct mapping of the data being transferred into an Ethernet data frame.

Adhering to standard protocols used broadly in other domains brings accelerated maturity, cost savings, potential enhancements generated by other applications, and future-proofing. Being generic, these protocols create a substantial overhead. Previous generation protocols developed specifically for the power industry are much leaner and more efficient.

3.1. Standardized data models

The vision of 61850 was to not only standardize the communication mechanisms but to also define the semantics (meaning and behavior) and syntax (structure) of the data being communicated. To this end, 61850 modeled numerous real devices and functions found in the substation. These models and functions are organized into what are known as Logical Nodes (LN). A specific protection function is then modeled through the logical connection between the logical nodes that exist throughout a substation.

Another key vision of IEC61850 was the ability of a device to describe itself. Self-description allows a server (IED) to send, on request, a textual description of all the data items and attributes know to the server, allowing the client to automatically create a database of data items. This capability enables automatic configuration of multiple remote clients yielding significant time savings (in the SCADA realm) compared to existing techniques.

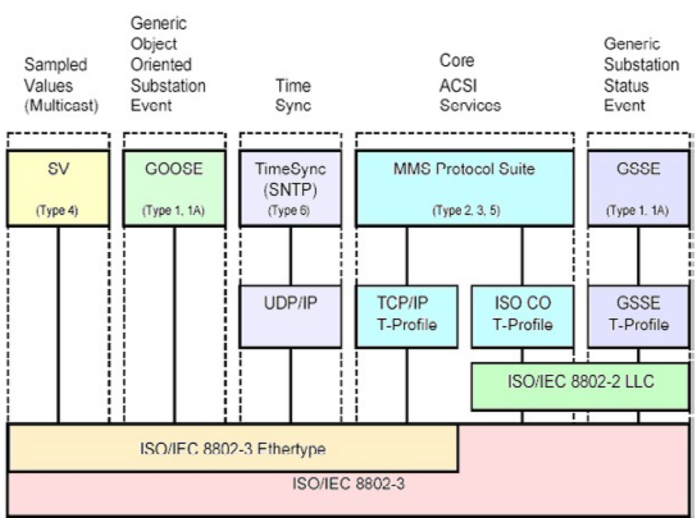


Fig. 2.
IEC61850 Communication Profiles.

It is worth emphasizing in this context that the IEC 61850 creates a false illusion of standardized P&C functions. The intent was to standardize the models, i.e. organization of data, and not the data itself or ways of producing the data. For example a distance protection function or a breaker failure function in two different 61850 implementations would use the same data types and will self-describe themselves in a standardized way, but will have different settings, different input and output signals and will respond, therefore, differently. Although the semantics of the data items are standardized, many of the functions are not interchangeable, nor they can always be configured to interact properly for protection purposes.

3.2 Standardized data access

Access to the data items was achieved through the creation of "abstract services". These services were created independent of any specific application layer and subsequently allowed for the mapping of these services to any chosen application. The concept of abstract services makes the protocol futureproof, as it is migrate-able to whatever the future brings in the way of next generation application layers. Additionally, the layering of the other communication protocols enables migration to new technology as it becomes available. A good example of this is the fact that the present version of the Internet Protocol (version 4) is in the process of migrating to Version 6. Because of its layered implementation, IEC61850 will be able to migrate by changing out only one layer of the overall profile.

3.3 Virtual DC wiring – GSSE and GOOSE

The logical architecture of 61850 permits Logical Nodes to be distributed in multiple physical devices throughout the substation. In order to interconnect these distributed nodes, a fast, distributed, and reliable delivery mechanism was needed. The solution to meet the identified requirements is known as the Generic Object Oriented Substation Event or the GOOSE. The GOOSE was originally defined in the work for UCA and was only designed to carry binary status information (virtual dc wiring over Ethernet LAN). In the migration to 61850, the IEC GOOSE brings with it several desirable new features, namely:

- The ability to directly send analog data values
- The ability to send data via a VLAN (Virtual LAN)
- The ability to set the priority of the message through a switch

The IEC GOOSE, in contrast to the UCA GOOSE, carries a user-defined dataset. The dataset can be configured with any data object in the relay such as Volts, Watts, Vars, breaker status, etc. The data items in the dataset carry the same type (such as Float 32, Integer 16, Boolean, etc) as the original data item. In the application of transmitting power flows, data, in engineering units, can be easily transferred among multiple locations as needed.

With the UCA GOOSE, when the multi-cast packet left the station, the packet would travel anywhere there was an Ethernet switch. This resulted in GOOSE packets being delivered to more locations than they had to be. A new feature supported in the IEC GOOSE is the ability to logically restrict the flow of data to a particular broadcast domain through the creation of a Virtual Local Area Network or VLAN. This dataflow restriction is achieved by adding 4 bytes to the Ethernet data frame per the IEEE 802.1Q standard. Once identified as an extended Ethernet frame, a device (switch/bridge-router) in the network can decode the VLAN ID or VID. This ID is read by the device and directed to those ports programmed with the same VLAN ID thus partitioning the physical network into logical sub-networks.

The third area addressed by the IEC GOOSE is that of Ethernet Priority in communication. Ethernet has traditionally been known as "non deterministic" in that collisions on a shared wire made the delivery time of a message a random variable. With the introduction of Layer 2 full-duplex switch technology, Ethernet collisions no longer exist. Switches receive all messages and store and forward them to the destination locations as programmed. It is possible for a single port to have several messages queued for delivery which would add a certain amount of delay in the processing of a message. Ethernet Priority, however, even removes this delay in most cases. Upon receipt of an Ethernet message with high priority, the received message is moved into a high-priority queue and messages in the high-priority queues are sent before those in the lower priority queues resulting in a higher Quality of Service for the GOOSE messages. However, potential delays of critical messages such as GOOSE/GSSE, all with the same high priority assigned, could be a factor. Guidance for using the provided priority mechanisms and testing to validate the desired performance are not defined yet.

GOOSE messages incorporate quality and test bits. The former are meant to signify the "goodness" of data; the latter are meant to facilitate testing of distributed schemes. The Standard, however, does not mandate the creation of or the response to those bits, leaving such issues to the user.

GOOSE messages typically incorporate channel monitoring by a simple method of sending messages even in the quiescent state. If a message does not arrive in a pre-defined window, communication loss is declared and the incoming signals are replaced by pre-defined values including on, off, last valid, etc.

The UCA binary GOOSE triggered transmission upon state change. Similarly, the IEC GOOSE specifies that a GOOSE message is to be triggered not only on a status change but also on a data change (i.e. – change of an analog value greater that the dead band setting for the data item).

3.4 Virtual AC wiring – Sampled Values

One of the most forward-looking elements in the IEC61850 vision is that of providing an interface between the "process" of voltage, current, and status measurement and the protection and control devices in the substation. This interface is defined in the Standard as the Process Bus. IEC61850 defines how samples of voltage and current can be transmitted over an Ethernet communication channel.

The primary driver for this interface is the continuing emergence of non-conventional current and voltage transformers. Although available for over 15 years, the general adoption of such devices has been stymied – according to some – for lack of an inter-operable solution.

The concept of a Process Bus has a wider application, though. If elimination of copper field wiring is a target, there will be a need to digitize the raw process information in the switchyard, close to the primary equipment, and ship it digitally between devices in need of this information. This applies to traditional CTs and VTs as well as other mostly binary (on/off) information in the yard. This capability is essential for success of the process bus concept, since the utility industry cannot make a business case for replacement of all the existing instrument transformers at the same time that protection and control systems in the control buildings are being upgraded.

It seems that the existing version of the Process Bus (Parts 9-1 and 9-2) is primarily driven by a much narrower application with non-conventional CTs and VTs.

3.5 Interoperable Format of IED and Substation Configuration

The 61850 Standard hints at a set of engineering tools that address various tasks required in the design and implementation of a substation automation system. These include project design, configuration and documentation tools. The Standard does not attempt to define the tools themselves. Instead, it defines a model of the IEDs and their communication services and defines a common file format for the description of this model. This standardized file format is used for the exchange of information between the various engineering software. These files have the potential to replace the schematics, wiring diagrams and point lists currently used to develop and document the substation design.

Project design tools are used in the planning stages of a substation automation system. The system designer can specify the substation primary equipment in the form of a single line diagram. The high-level functional requirements of the system are defined here as well as the signaling requirements to the primary equipment. At this point, pre-configured devices (IEDs) that will be used to implement the automation system may also be selected and assigned.

Configuration tools are used to parameterize the various IEDs to produce a working system. This task may be further broken down into the configuration of substation level functions and parameters (system configurator) and the configuration of autonomous IED parameters (IED configurator). The system configurator makes use of the specifications developed in the project design tool. The system configurator also utilizes standardized files that describe the capabilities of the IEDs. These tools also are responsible for the transfer of the configuration to the IED and for management and archiving of IED configurations.

Documentation tools are responsible for the automatic generation of standardized documentation that is specific to the substation automation project. These tools are again subdivided into tools for documentation of the external equipment (i.e. CAD tools) and tools for documentation of IED parameters. CAD tools are used to develop AC and DC schematic diagrams for functions that are external to the IEDs and to document (list) the physical connections to the substation automation system. IED parameter documentation includes lists of signals that interface with substation equipment, internal logic, and parameters.

3.6 Envisioned Design Process for IEC 61850 P&C System

One could envision a greatly streamlined design process using the tools described in the previous subsection. The ultimate design process could be envisioned as follows:

The design standards group converts its standard substation design into a 61850 document. This file would consist of a single line diagram showing the primary equipment populated with logical nodes representing the required functionality for the substation.

The projects engineer would use this master file to create a design for a specific substation using a generic project design tool. This could entail copy-and-paste operations to add additional bays, for instance. The resulting file might become a tender document distributed to various substation automation vendors. The engineer involved in bidding would import the document into a system configuration tool and map the logical nodes to physical devices of choice. The modified file may become part of a bid document showing the location of IEDs and their associated functions.

After the project has been awarded, detailed engineering would commence. The substation integrator would import the file used for bidding into a substation configuration tool. At this level, the communications services of the IEDs would be configured for the implementation of distributed functions. Data sets could be created by drilling down into specific logical nodes to select the desired data (self-described). The resulting GOOSE messages could interconnect devices through a simple drag-and-drop process. Report applications (SCADA) and sampled value applications (process bus) would be implemented in a similar fashion.

After all system level functions have been implemented, the output file would be exported to the IED configuration tool. Here the remainder of the IED parameters would be configured. The output file from the IED configurator would be ready for download into the IED and could be used to automatically generate the documentation for the project.

The above describes a process in which little engineering effort is duplicated or repeated, and the entire project is delivered in an electronic format that starts as a bidding document and grows into detail design equivalent to IED settings as it goes through various design stages.

4. Unanswered Questions – What's Missing?

From the beginning, the scope of the IEC 61850 project was to define a protocol for the communication of information. Specifications for the actual design, commissioning, operation and maintenance aspects of a complete system architecture appropriate for integrated substation applications were not part of the scope. This section will attempt to highlight some of the areas where further development is required in order to facilitate delivery of a complete, working system capable of utilizing the vision of IEC 61850.

4.1 High-Level Requirements for Next Generation P&C System

Given the way protection and control systems are deployed and operated today, the following are highly desirable features of the anticipated next generation protection solution. The following statements apply mainly to the protection aspect, and not to the relatively complete, and mature client-server (SCADA) portion of the 61850 set of protocols. A key element in any design is to first establish the basic functional requirements; these in turn will permit development of appropriate solutions. The following items are intended to address some of these requirements:

Availability. The protection architecture of an integrated system shall have availability equal or better than today's systems. Given the extremely high reliability of instrument transformers, connecting cables, and interposing/lockout relays, today's availability is primarily driven by the failure rates of multi-function IEDs, and is expected to be in the range of 100 years of MTTF. There is a dramatic impact of the count of electronic devices comprising a fully integrated system ("merging units", Ethernet switches, time synchronization sources) on the availability of the system. A successful architecture will have to be engineered to retain equivalently high availability regardless of the number of devices in the scheme. Not meeting this requirement will be damaging to the concept and its present momentum, and may result in erasing all initial savings by increasing the subsequent cost of ownership.

Cost-efficiency. Microprocessor-based relays have been adopted despite the reduced performance of early models compared with the preceding generation of static and electromechanical relays, because of their attractive initial price equation. A successful architecture will have to prove significant reduction of the total cost of installation and ownership. This shall account not only for the initial engineering, construction and material cost of a solution meeting all other requirements, availability in particular, but also for cost of maintaining extra electronic equipment that replaces virtually maintenance-free items such as cables and associated drawings, pushbuttons, interposing relays, etc. It is the cost equation that separates what is technically possible from what is eventually manufactured, given a chance to mature, and be deployed in the field.

Purpose-driven design. Implementation details, the intended focus of the 61850 Standard, are secondary compared with the challenges of architecting a robust system. The overall system design should to be purpose-driven, with cost and simplification being primary targets.

Switchyard wiring offers the biggest saving opportunity. With non-conventional CTs/VTs being adopted very slowly, the practical solution for cost-efficient substitution of the yard copper wiring focuses around placing electronic devices in the yard to interface with physical secondary signals at their origin. This presents a challenging task in terms of architecting the system particularly in the area of redundancy. Presently the IEC 61850 Standard specifies that a single failure shall not take down the communication but the document does not address the issue of architectures required to obtain a high degree of availability. Additionally, issues such as stand-by data, dynamic data substitution, etc. are not addressed. Much work remains to be done to turn these concepts into reality so practical systems can be delivered.

Another significant saving opportunity is in the area of lockout relays. The Standard does not acknowledge existence of lockout relays, nor does it address the issue of practical implementation of the lockout functionality in the soft space.

Overall, the cost and simplification benefits need to drive practical architectures, and those architectures should drive the interoperability standards. When reversed, the unfortunate result may be a lack of important features and/or the introduction of concepts that will never be used.

Another aspect of a purpose-driven design is to use right tools for a given problem. This requires in-dept knowledge of protection and control engineering and must not be done from a generic and oversimplified perspective of moving real-time data between various devices. A successful system will have to be designed to overlap with and take advantage of the way the primary equipment is designed, operated, and regulated by various agencies, i.e. taking into account this particular "process to be controlled" known as a power substation.

Advancements in technology must be closely monitored and old assumptions must be critically re-visited. For example:

- With a limited number of signals belonging to a given zone of protection (characteristic of the process), and the cost of fiber being very low already (evolving technology), what is the role of Ethernet switches on the process bus level, i.e. in the real time critical network intended for protection?
- Or, assuming secondary signals are produced by traditional instrument transformers, and elimination of the yard wiring is one of the primary targets for the new architecture, while systems A and B remain independent, what is the value of interoperability for the sampled values?
- Or, if interfacing with physical signals at their origin is a part of the solution, why does the envisioned communication protocol seem to be heavily biased towards uni-directional transmission of fast analog values, instead of bi-directional transmission of co-existing binary and analog values?

Segregation of Functions. Today's solutions show a great degree of separation. Protection systems A and B are separated; zones of protection within each system are separated; a given zone can be protected with a single device manufactured by a single vendor; a given IED can be maintained with minimum interactions with other devices (breaker failure is a rare exception); firmware upgrades can be performed with little or no interactions with other devices; a given application can be engineered using minimal and well defined interfacing points with other applications; a given IED can be set up using a single set up software, etc. The above is too often taken for granted, but could be jeopardized when using communication-based solutions that go too far. A successful architecture will have to maintain simple separation boundaries between elements, or users will become overwhelmed with complexity and interactions while engineering their protection and control systems.

Separation of Secondary Equipment/Manufacturers. There is a practical value in limiting the number of pieces of secondary equipment interacting with one another, and reducing or simplifying the interactions themselves while fulfilling the mission critical task of protecting the power system. Today's architectures depend on a small number of devices or signals for protection. In particular in order to protect a given zone, it is required to synchronize measurements for the few signals that bound the zone. This is done internally to the relay, and does not involve synchronization to an absolute time, or synchronization among all signals in the substation. Also, today's solutions do not require third party devices to produce and move data required for protection. Dependency on such devices must be considered substandard in terms of overall availability of the system, complexity, separation of functions and equipment manufacturers, upgradeability, etc. and shall be avoided at all cost unless necessary to achieve a more valued goal. Today relay manufacturers attend to all sorts of underlying processes taking place in a modern relay. Such a complex product is controlled by a single firmware, tested as a whole, engineered to work optimally as a system, supported by a single set up program, and guaranteed by a single vendor. Some concepts promoted by the IEC 61850 seem to go in the opposite direction. For example, a solution that requires four devices (merging unit(-s), Ethernet switch(-s), protection IED(-s), and source(-s) of time/synchronization) coming from several vendors; having each its own firmware and a step up program, may face significant acceptance problems. Building tightly coupled systems out of several microprocessor-based devices by several vendors brings extra risk and complexity probably doubling with each new type of device, or new vendor adds to the equation. For example consider the exercise of troubleshooting a GPS-supported line current differential scheme, with communication converters, and multiplexers. When one assumes that each of the four system components could be supplied by different vendors, the significance of this issue becomes evident – all parties may comply to applicable standards, and still the system may have problems. The user is ultimately accountable for making it work. Maintaining control of type test integrity becomes very convoluted and from a responsibility standpoint, nobody is in charge. There is no easy way to control the impact of a change in any one element, especially after the system goes in. The overhead cost associated with working with several other vendors while developing or modifying products will get eventually passed on the user. Given the complexity of the 61850 proposals the initial product fine-tuning phase is not going to subside quickly.

Maintainability. Today's systems are engineered by users to meet their operational and maintenance criteria. This is possible after decades of accumulated experience and owing to common denominator interfaces between the relays in the form of copper wires or simple serial protocols, and relative indifference of the way the relays, including IEDs, are designed, on the operational and maintenance procedures at various utilities. By migrating the input and output signals into communication media, the user experience and training base will have to be significantly re-visited. Even more, the issue of maintainability and testability of the system will shift towards inner workings of the IEDs, putting more burden on manufacturers in order to facilitate the processes traditionally under the full control of users. Both the new architectures and communication protocols will have to be designed to aid this process. The IEC 61850 Standard does not address this issue – it restrains from suggesting any practical architectures and stops short of mandating the response of compliant devices to test values or substituted data, making these concepts of a very low value. The above assumes that users would accept testing or isolation performed in software. Those who would insist on physical testing and/or isolation are left without any practical suggestions.

Determinism. Protection is considered a mission critical task, designed for worst-case scenarios in both primary and secondary systems. As such it requires high level of determinism, and must be designed assuming worst-case scenario within the secondary system itself. Determinism is required to make the engineering task possible (example: worst-case message delivery time for calculations of the coordinating timer in a blocking scheme, or a trip time of a breaker fail scheme); but also to guarantee that the initially commissioned version does not deteriorate as the system is expanded, devices replaced with different models or from different vendors, firmware is upgraded, critical communication settings are altered, etc. A solution that requires re-engineering or re-testing of large portion of the scheme each time a firmware on an Ethernet switch is upgraded, or a new bay is retrofitted and added into the highly integrated communication based P&C system will face acceptance problems if determinism cannot be guaranteed. Lack of determinism and/or lack of future-proof solutions could result in extra engineering, troubleshooting, and testing after the system is initially commissioned to the extent that initial cost savings will be jeopardized.

Right degree of interoperability. Today users accept "proprietary" solutions as long as the size of the proprietary subsystem is small enough, practically limited to a single zone of protection. Indeed, today's transformer or line IEDs are entirely proprietary in terms of collecting their data from standardized analog interfaces, processing it, and executing their controls. The need for digital interoperability within the substation exists in two areas only: client-server SCADA protocol, and peer-to-peer binary signals for interlocking, breaker fail initiate, auto-reclose initiate, closing and perhaps tripping. A successful solution needs to deliver on interoperability in the areas that are required while addressing all practical aspects such as performance, ease of use, future-proofing, determinism, testability, and maintainability.

Clear design responsibilities. By proposing certain communication-based concepts for exchanging real-time protection-critical information between devices, but restraining itself from providing any architectural proposals for the new system, or addressing specific operational requirements, the IEC 61850 Standard invites various parties from users, through equipment vendors, to independent software companies, into a group design activity for the mission critical system known as power system protection. Involvement of users shall be noticed – the concept was meant to address the problem of understaffed utilities, high cost of engineering, and lack of standardized P&C solutions.

Given its complexity and performance requirements, a successful solution will have to come from parties focused on the complete system, not on its detached elements. Substantial development cost may be required to complete the task, with the outcome being a considerable paradigm shift facing acceptance challenges from both users and regulators. Close cooperation and risk sharing between users and manufacturers will be required for the concept to succeed.

Again, the preceding observations apply to protection functionalities, and not to the relatively simple and mature client-server (SCADA) portion of the 61850 set of protocols.

4.2 Allocation of IEDs and P&C Functions to Zones of Protection

Protection engineers are accustomed to long-standing rules for applying protective relay units, more recently multifunctional boxes, to the various zones of protection. Some of these rules are based on hardware unit failure impact criteria that remain relevant regardless of how the relays are networked for data communications. However, the combination of design features in the latest generation of microprocessor relays, and the control connectivity of IEC 61850 communications (especially GOOSE/GSSE messaging) provide the tools to meet these criteria in better ways and with less equipment than before. Note that the IEC 61850 Standard advises the user that redundancy will be required, but it does not specify how to architect or interconnect the relays and IEDs. In the ensuing text, interconnection architectures and other issues are illustrated.

It is assumed that, for a critical bulk power transmission substation or line, two totally isolated redundant systems will be required so that there is no credible single point of failure that can disable both systems. We call these System A and System B rather than Primary and Backup, since either must be capable of the entire protection job if the other has failed or is out of service. NERC reliability criteria demand this redundancy to guard against the impact of single failures, and NERC offers specific implementation guidelines. It is noted here that some of those guidelines are derived from traditional protection and control architectures, and that the technical requirement for no single point of failure can be met by entirely different approaches.

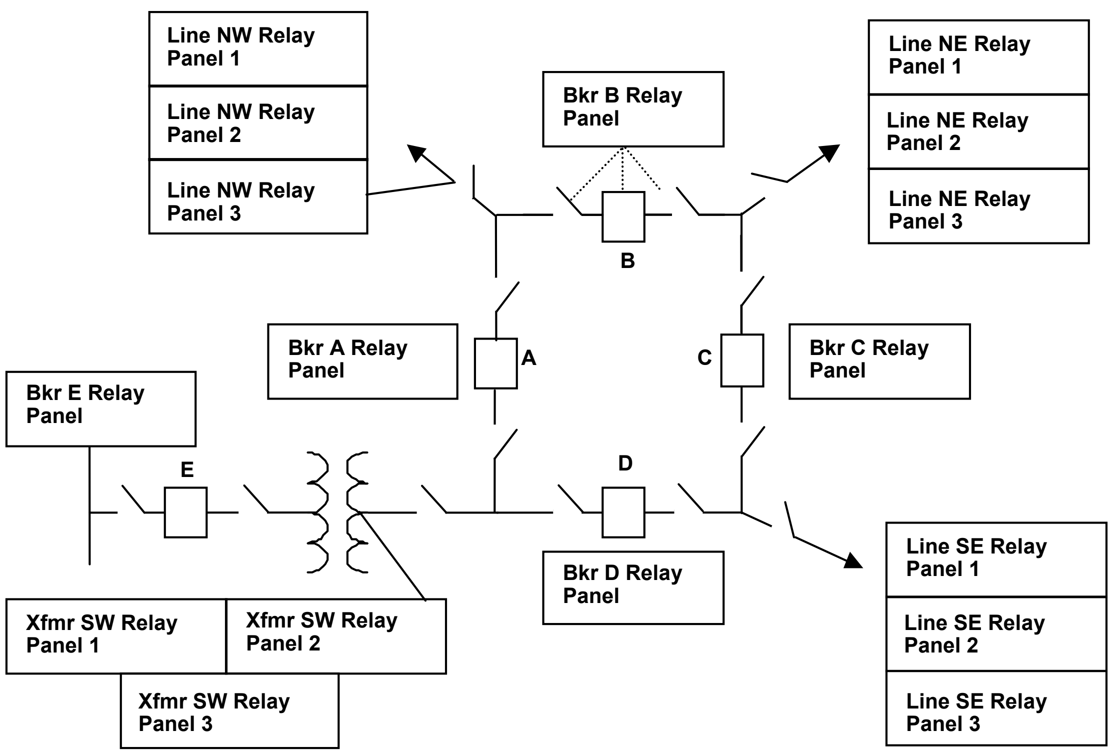
Some utilities use more than two redundant systems, but adding more equipment than needed does not always help – it certainly increases the number of failures and repairs to deal with. The technical capabilities of a P&C system based on a 61850 LAN has technical features that can reduce the justification for these third and fourth tiers of redundant relays, as we explain further below.

Refer to Figure 3. Here we see a typical ring bus with three lines and a transformer connected. Ring buses or breaker-and-a-half buses are notable for the fact that each zone of protection – a line, bus, or transformer – is fed by multiple breakers. Each breaker must have its own control and protection features. Accordingly, the traditional architecture for such a substation features zone protection panels, having only the relay(s) and control auxiliaries that apply to that line, bus, or transformer. For each zone that is important to power system security, there are at least two separate redundant relay panels. There are separate breaker panels, one per breaker, where all the breaker-oriented protection and control functions and auxiliary devices are installed. These typically include breaker and disconnect switch controls for operators, breaker failure protection, automatic reclosing, and lockout switches for breaker failure actions. As Figure 3 shows, a breaker panel interacts with each of the two adjacent zone protection panel pairs, for example to receive breaker failure initiation or reclosing initiation. Similarly, each protection panel pair interacts with the two or more breaker panels for the breakers connecting to the zone.

Looking at this standard design, it is clear that early-generation microprocessor relays with line protection plus breaker failure and reclosing were not useful (they are potentially useful for less critical subtransmission and distribution applications where a line is fed by a single breaker from the bus, and a common failure of line and breaker protection will have only localized impact on the power system). However, the latest generation of microprocessor relays from several manufacturers have breaker functions for two breakers, with a separate set of current input channels for each breaker. Zone currents are summed from the breaker inputs.

These next generation relays can be applied in the newer architecture of Figure 4. Here, the breaker functions reside in the zone relay boxes, eliminating the breaker panels and the separate breaker control and protection equipment. While the failure of a relay unit can also take out the breaker functions included in it, note that there are now redundant functions for each breaker – not a feature of the old Figure 3 architecture. Therefore, the new architecture meets agency reliability criteria for no single point of failure, and with far fewer relay units than before. In many cases, there are four redundant breaker function groups for each breaker – more than we need; some can be turned off for simplicity.

Fig. 3.
Conventional Architecture for Zone and Breaker Panels.



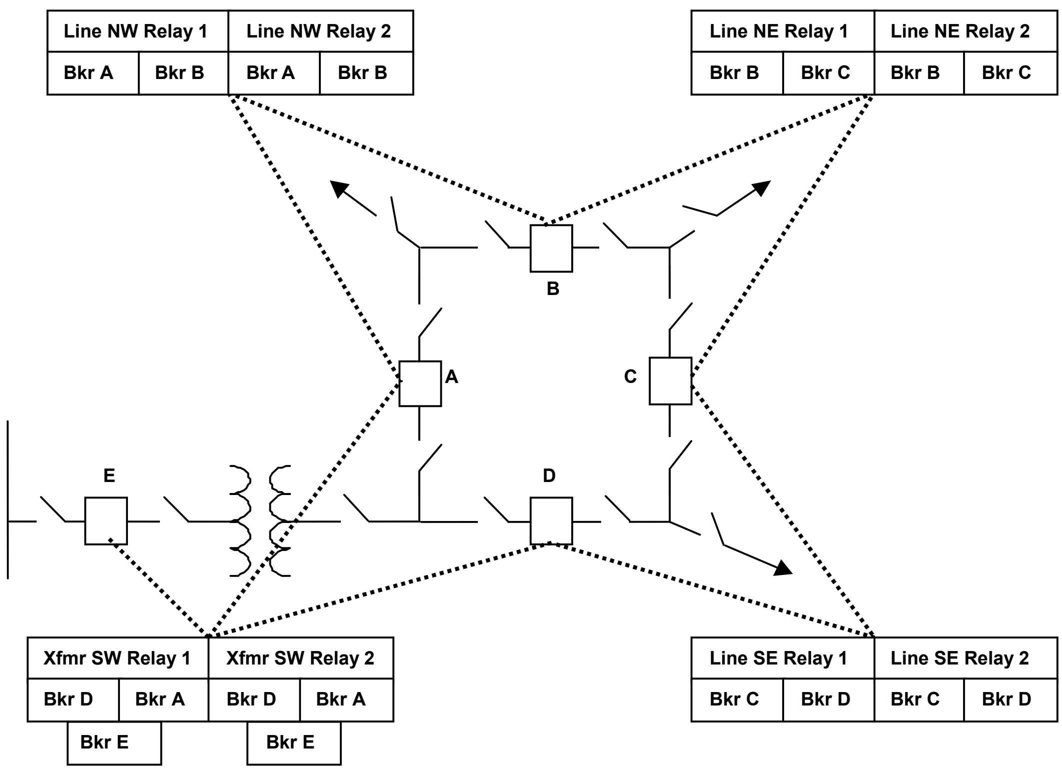
None of these new arrangements for distribution of breaker functions are directly related to use of a LAN with IEC 61850 messaging. However, a pair of redundant 61850 Ethernet LANs provides the means for communications and control among the breaker and zone functions that would require complex and confusing wiring and mounting of auxiliary devices. GOOSE/GSSE high-speed control messages are especially suited for breaker failure initiation, breaker lockout actions when a breaker failure occurs, reclosing initiation, reclosing function control transfer if the normal relay with line reclosing responsibility fails, and assignment of local manual control functions to relay pushbuttons (as a backup to a substation computer that would be designed into a modern substation for operator use). It is these architectural opportunities and the cost savings they yield that help users to make a business case for the benefits of designing a new substation using 61850 LAN communications. In the example here, we eliminated five breaker panels, and a mass of wiring and auxiliary devices, finishing with an installation having only 8 zone relays on a small number of panels.

There is another important benefit of the new architecture with its dual redundant 61850 LAN communications that is not apparent from the figures. An important feature of the GOOSE or GSSE messaging is that messages are transmitted periodically from each relay that broadcasts, to all of the subscribing relays on the network. Normally, the messages are telling the receiving devices that nothing unusual has happened and that nothing need be done. However, the periodic transmission of these no-action messages monitors the performance of the control connection, and any failure of a relay or a LAN component (e.g optical fiber, or Ethernet switch port) can generate an immediate alarm to maintenance personnel. While the second redundant system and its LAN continue to protect, the failure of the first can be rapidly repaired.

On top of this capability, the relay processes these GOOSE messages through the same hardware and outputs that are used for other protective operations. Therefore, if the relay processor is running, and is routinely operating its output for zone protection or for manual SCADA control, then we know that we have a completely monitored and tested chain of functions that will carry out a major lockout action if needed.

Note that conventional wiring and lockout switches have no such overall self-monitoring capability. Furthermore, functionally testing a device like a lockout switch is so awkward and disruptive to power system operation that it is rarely if ever done – we tend to hope these devices will be trusty and reliable, but we are not sure about them. Because of the ability to demonstrate that two redundant systems are sure to work, and can rapidly repair one that fails, we have a case for avoiding the use of three or four redundant systems. Taking this simplification cuts the purchased equipment by a third to a half, reduces long-term maintenance costs by a similar amount, and yields floor space, inventory management, and settings/coordination management benefits.

Fig. 4.
Use of Microprocessor Zone Relays with Multiple Breaker Functions Included.



While the developers of 61850 were aware of these opportunities and designed the system to bring them to users, they are not written into the Standard, or other public domain publications. It takes some application experience and insight to get these important benefits.

4.3 AC Signals

The cost of copper cabling typically applied by most utilities (engineering, drafting, materials and installation) represents a significant fraction of the total cost of a substation. Digital solutions that replace many copper cables with relatively few fiber optic communications cables are therefore very attractive and have the potential to save considerable amounts of money.

Long cabling applied today has some impact on quality of the used AC signals. CT saturation is the prime example. However with the extremely low burden of modern microprocessor-based relays dramatic reduction of AC cabling does not make much difference. Other non-ideal behavior associated with instrument transformers affecting AC signals, such as frequency and transient response are typically dealt with via improved protection algorithms that can better cope with signal distortions attributed to long cabling.

Non-conventional instrument transformers promise better signal quality, but those benefits are not dependent on using digital communications to distribute the signals. Lesson learned from successful adoption of microprocessor-based relays makes one believe that it will be unquestionable cost saving rather than better performance that would bring the non-conventional transformers into the mainstream application.

Safety issues such as rising potentials are more of a problem and could be eliminated or reduced when using communications-based AC signals. In this context, despite their 15 years of existence, the non-conventional transformers are yet to see their widespread adoption.

It is important to consider how fiber systems can be deployed without sacrificing the high reliability currently enjoyed with copper. Important considerations are the number of devices connected to any one communications link, time synchronization, response to loss and recovery of the synchronization source, dependence on any one master clock that could be unavailable, element removal for maintenance, availability of test software, and ultimately, user acceptance.

A significant unanswered question is the actual design methodology required, both at the system and device levels, to make the change from the traditional copper cable approach to carrying AC signals to the digital alternative. When making this transition from traditional substation practice employing many copper cables individually wired to instrument transformers, an important consideration is the type of AC signal to be carried and the associated performance requirements. AC Signals used by P&C systems fall into two general categories – time averaged and instantaneous.

Time averaged signals are those that inherently undergo some sort of integration process as part of the basic signal acquisition or later as part of the calculation or application where the signal is used. Examples of time averaged signals are operating measurement telemetry, such as per-phase Amperes or three-phase Megawatts. Time averaged signals typically experience latencies in the range of 1 to 4 seconds, with no detriment to the end application or user. Applications based on remotely accessed time average values on the client-server basis have been used for decades initially via RTUs and recently using protection IEDs.

Instantaneous signals are those which are utilized in time-critical applications such as protective relay algorithms and typically contain sampled values of power system AC quantities sent in real-time. An example of an instantaneous signal is the secondary voltage of a capacitive voltage transformer used in a distance relay algorithm. In this case, permissible data latency may be less than 100 microseconds.

It is taken for granted that copper based signals can easily be shared. It is not so with communication based signals. One of the fundamental architectural issues is how to provide for overlapping zones of protection, with mandated redundancy, but without multiplying the number of required IEDs of various types (merging units, Ethernet switches, time synchronization means, IEDs) to the extent of ridiculously low reliability / availability of the complete system. The point-to-point 61850 process bus suggestion (part 9.1) calls for an unreasonably high number of merging units. The switch-able (LAN-based) 61850 process bus suggestion (part 9.2) yields a convoluted scheme with time synchronization, LAN, testability and maintainability issues.

When carried on a communications network, signal latencies are introduced by the communications medium itself, in addition to latencies introduced by the signal acquisition interface and end processing application. At any given time, these latencies may be static or random, depending on the communications topology deployed. Latencies may also change as a result of system re-configuration or fail-over, for example following a communications device failure in a redundant system. Communications latencies are therefore of considerable concern in the design of any substation LAN-based or point-to-point topology because these extra delays, if not carefully examined, may fundamentally alter or impair the performance of the end application. Complicating matters is the fact that communications latencies are often difficult to measure or even predict. LAN architectures and issues are discussed later in this section.

The usual approach to managing communications latency with time averaged signals is to factor the worst-case expected latency into the overall response required by the application. The solution is not so simple with instantaneous AC signals. Practical usage of instantaneous signals requires accurate synchronization of measurements at all involved locations. For example a distance functions requires the voltage and current signals be synchronized. If delivered by two independent devices, these signals must be referenced to the same time base. Time synchronization issues are discussed later in this section.

Treatment of lost data is a significant aspect in the “line up” algorithm. As each expected packet can be lost or arrive after a variable time delay, the algorithm must be smart enough to wait for pending data and abandon at a given point in time when the maximum delay time is exceeded.

Another consideration when making the transition from P&C systems using individually copper cabled instrument transformers to solutions relying on digital communications is fault tolerance. The existing copper solutions have the advantage of being extremely reliable from the overall station point of view, because there are very few common failure modes, short of a fire in a cable trench. Availability of distributed P&C architectures utilizing fiber-based AC signals are discussed later in this section.

All of these issues are solvable and must be resolved in parallel with the IEC 61850 Standard, but the quest to realize the potential cost savings will require concerted engineering effort.

A weakness of the 61850 vision in the context of the process bus, is the absence of workable architectures that would satisfy a long list of technical, operational, and regulatory issues. Acceptable architectures may require specific tools, or broadly defined rules for communications. These rules are obviously not there, and what has been specified only enables lab-projects for connecting a merging unit to a compliant IED.

4.4 DC Signals

Another unanswered question is how to effectively implement a digital alternative to the conventional hard-wired connection of discrete DC signals within the substation. DC signals used by P&C systems also fall into two general categories – those that indicate the current state of an element or system, and those that represent time-critical actions, such as protection trips.

The first category includes signals such as alarm and status points used by SCADA systems and the state of discrete conditions such as switchgear interlocks, position of reclosure selections, etc., but does not include the status of breaker auxiliary switches used in breaker failure and other critical protection applications. Signals used by control systems are generally one order of magnitude less critical with respect to delivery time than those used by primary protection systems. Inherent latency times for status signals are typically in the range of 15-20ms, whereas alarm and condition states may have acceptable latency times of 1.0 s or more. Existing communications performance in practically any topology (point-to-point, star LAN, bus LAN, etc.) is quite capable of meeting this level of performance in control systems of up to 1000 points or more.

The second category poses a much more significant design and application challenge for emerging communications-based alternatives. This category includes most input and output signals used by primary protection and teleprotection systems. Backup protections generally do not require this level of performance. Category two signals are considered to be those that require reliable delivery in less than 4.0 ms, under the worst-case guaranteed system traffic conditions. If we assume that the portion of protection circuitry between existing relays and the associated switchgear is implemented with auxiliary relays and miles of wire and cable, the fastest protection trip signal times are typically 4.0 ms and are determined by the choice of auxiliary relay used for high-speed applications. This is frequently used as a benchmark when evaluating digital alternatives. Developers of the current generation of IEDs have generally met this level of performance for the execution of discrete internal logic, analogous to separate auxiliary relay logic. However, current substations still use many thousands of dollars worth of DC cable to interface IEDs to switchgear and other devices in the switchyard and within the relay building.

From a cost point of view, the same incentive exists to eliminate or reduce DC copper cabling as there is with AC cabling. Similar communications latency considerations apply also, except the need for time stamping is generally limited to the appropriate identification of discrete events. In the case of discrete protection trip signals, communications performance is impacted by the extremely random nature of this traffic. For example, say a substation runs normally for two years and then suddenly a bus fault occurs, followed by a breaker failure. Immediately, many IEDs start sending huge amounts of traffic and the communications infrastructure suddenly reaches 110 % of capacity. Some signals may therefore experience delay or even become lost if the design doesn’t anticipate this type of response.

Converting discrete signals formerly carried via copper wires to their LAN-based equivalent messages also significantly changes the failure mode from the perspective of the receiving device. In a traditional wired circuit, a contact closes at the sending end and an auxiliary relay coil picks-up at the receiving end. The auxiliary relay remains energized for the entire length of time the sending contact is closed. The length of time the sending contact is closed also conveys information and in fact is the basis for many time co-ordination and backup-schemes. In a LAN-based scheme, this transaction is replaced by discrete commands sent digitally over the network. A message is sent signifying the “on” state and another message may be sent later signifying the “off” state. The receiving application must keep track of the context of these messages. If, for example, the system fails and the “off” message is never received, the receiving application could be “stranded” in an undesirable state for an extended period, unlike the wired system in which the receiver will “fail safe” and turn itself off. Therefore, a practical message delivery system for a substation-LAN based messaging protocol must include additional features such as a regular heartbeat message or other equivalent strategy to identify the continuity of the sender. The receiver also needs to have a strategy permitting it to go back to the reset or default state upon loss of the heartbeat message.

An additional factor affecting reliable message delivery is the choice of the LAN architecture itself and the various redundancy strategies that may be established. For example, simple networks connected with shared media switches may cause collisions to occur between messages sent nearly simultaneously, thus impairing message delivery of one or all of the sending stations. Switch networks greatly improve the situation, but each system type still needs to be carefully evaluated with respect to the performance of critical traffic.

The network architecture or topology also has a bearing on the reliability of message delivery in a digital substation. For example, many older SCADA architectures were based on the master-slave concept, in which the slave devices essentially are data senders and discrete I/O devices only. Many newer substation integration architectures are based on the peer-to-peer concept, in which system elements exchange information but are also capable of autonomous behaviour on their own.

Solutions that replace DC cabling with fiber optic communication solutions are becoming available. It is paramount that the application topologies proposed carefully consider and ultimately specify explicitly the maximum performance any given combination of IEDs, field acquisition devices and communications elements is capable of. Simple application rules are required for consistent deployment on actual projects.

Appropriate redundancy or equivalent strategies are also required to guarantee acceptable overall system reliability despite the consolidation of signals on a multiplexed bearer media instead of over many simple and discrete wires. Fiber alternatives also offer significant advantages over DC cables with respect to immunity against (induced) interference and transient (capacitive) effects that tend to be troublesome with the current generation of IEDs and teleprotection equipment. The potential exposure to battery grounds is also significantly reduced.

4.5 LAN Architectures and Issues

As communications in the substation (and beyond) takes on a more critical role in the protection and control tasks of the utility, the enterprise communication architecture must be designed to meet the same critical design requirements of the equipment with which it is connecting. Specifically, the communication equipment must meet the same environmental and electrical specifications as the protection and control equipment.

In addition to the electrical and environmental specifications, the communication system must be available to communicate between the various IEDs in or between substations. The design for high-availability starts with redundancy in the communications from the IED. Redundancy in the IED can be achieved either through redundant port or redundant media. With redundant ports, there are two completely independent Ethernet ports built into the IED with each port having its own Ethernet MAC address and separate IP addresses. With two sets of addresses, the IED must constantly monitor both ports for information received and channel it to the appropriate process.

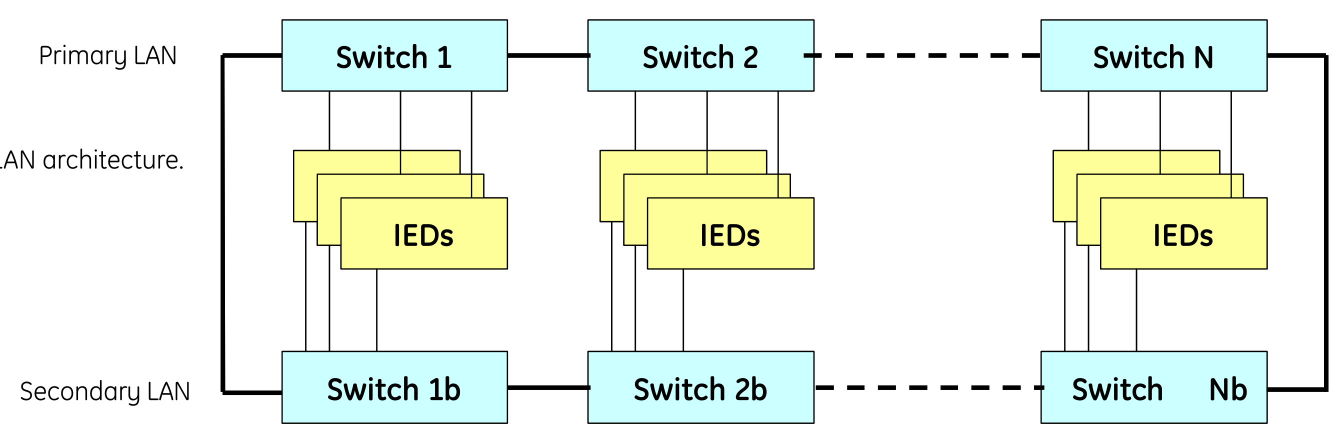
A second option for redundancy is that of redundant media. In this implementation, there is only one Ethernet port (one MAC address, one IP address) that is dynamically switched from a primary fiber port to a secondary output port. The switching is based on the loss of Ethernet link pulses on the primary connection.

Given redundant Ethernet on the IED, the next area to address with redundancy is the Ethernet connection junction. In today's implementations, it is almost a given that the connection between Ethernet ports will be performed by an Ethernet Switch. A switch operates at a logical level in the communication hierarchy, that is, a switch receives an Ethernet packet, reads the contents, and then decides how the contents should be processed and forwarded. In the processing of the packet, the switch first determines if the packet should be processed at all (a security feature to inhibit just anyone from unplugging an IED and plugging in a laptop in a substation). If the packet is to be processed, should it be processed with priority (a Quality of Service feature of Ethernet) and should it be delivered to only specific ports (Ethernet Virtual LAN option)? In the redundant architecture, each Ethernet output of the IED should be connected to different switches so that if a switch fails, communication to the IED can automatically be transferred to the back-up communication port on the IED. The two switches now need to be linked together so that a message received on one switch can be transmitted to any device connected on the other switch.

In order to optimize communication between switches, it is recommended that the up-link port be operated at a higher speed than that of the feeder ports. For example, if the feeder ports operated at 10MB, it is recommended that the Link ports between switches operate at 100MB or faster. Similarly, if the feeder ports are operating at 100MB, it is recommended that the Link ports be operated at 1GB.

Typically, an Ethernet switch can connect from 12 to 16 IEDs. For substations containing more IEDs that this value, multiple switches need to be linked together on a primary and secondary port basis, again with a connection between the group of primary and back-up switches. This configuration has a drawback in that if one of the switches being used to connect the primary group of switches to the back-up group fails, the connection to the back-up group is lost. This failure mode can be eliminated by connecting the groups together at both ends, effectively forming a loop. In general, Ethernet does not operate in loops; however, most switches in use today operate an Ethernet algorithm known as Spanning Tree. This algorithm is designed to detect any loops and to logically break the loop at a point. More specifically, there is a variant of the Spanning Tree algorithm known as Rapid Spanning Tree that can detect rings and fix breaks in structures in as little as 5ms. The resulting LAN architecture is shown in Figure 5.

Fig. 5.
Practical LAN architecture.



Many experienced protection engineers find discussion of these data communications issues to be dense and perhaps intimidating, because until now they have not faced the need to understand the behavior and performance characteristics of substation components like Ethernet switches. Furthermore, there is no part of the IEC 61850 Standard that guides designers and users on these network architecture subtleties. We encourage users to recognize that unavoidably, as P&C design technology moves forward, the behavior and characteristics of components like Ethernet switches will be as important to understand as those of protective relays if the P&C system is to achieve its availability, dependability, security, and maintainability goals. It is important for protection engineers to understand that the basics of IT networks are not difficult to understand, and that learning how to handle networking issues is no more difficult than learning about any new generation of relays. Incidentally, P&C engineering groups need to achieve peace and mutual understanding with the utility IT department, which can help with substation-enterprise integration, and which needs to understand the features of substation LAN messaging that are critical to power system security.

We explained above the existence of multiple ports in a typical modern managed switch, each port having its own queue of incoming and outgoing messages so that we never face the problem of collisions and lost messages. We also explained how new switches complying with the Ethernet standard IEEE 801.2Q can recognize priority and VLAN fields in the message packets (e.g. GOOSE messages) and can express-route or selectively route critical messages. There is more to consider from a relaying point of view. For example, full utilization of the two redundant P&C systems require that GOOSE messages pass between them, and that substation host devices and interfaces to the utility WAN be able to communicate with devices in both System A and System B. To do this, the designer needs to take advantage of the isolation that the ports of the Ethernet switches in System A and in System B can provide, and to interconnect them in a way that avoids single points of failure that could interfere with data communications in both Systems A and B. The designer needs to consider not only passive failures, like a broken fiber, dead port, or failed switch ; but also active failures of communicating devices that jabber unwanted message traffic or turn on emitters continuously. Switches and networking equipment could provide tools to handle these contingencies.

Maintenance personnel also will need to gain enough understanding of communication architectures including both physical topology and control mechanisms for data. For example, consider a relay that has primary and failover fiber connections to two different ports on two different Ethernet switches in System A as we described above. A technician who disconnects the primary fiber, or turns off the switch to which it is connected, may think that he has disabled backup tripping GOOSE commands from this relay to others on the LAN. He then may proceed to test the relay in ways that generate backup tripping request messages. He needs to understand that the relay may have detected the disconnected primary channel and failed over to the completely functional backup fiber and switch – all the messages will be delivered on time to subscribed relays in Systems A and B, possibly yielding unexpected and undesired tripping from the testing work.

4.6 Time Synchronization Architectures and Issues

A very important unanswered question is how will accurate, coordinated time services be delivered to all elements and processes within the whole integrated system? Advanced concepts within the IEC 61850 set of standards suggest digitizing protection input signals, currents and voltages, at the place of origin and providing the protection and control system with real-time stream of samples using a standardized protocol (process bus).

The idea of further reducing wiring substations by substituting switchyard cables with fiber optic cables is very attractive economically. This could be accomplished by applying non-conventional CTs/VTs and moving analog signals via fiber into merging units for de-coding, and subsequent digitization and presentation as the process-bus data. Alternatively, traditional secondary signals could be connected to dedicated interfacing devices in the yard for digitization and transport via digital fiber into the control house.

In both instances, protection relays as known today will be presented with information taken at various physical locations by various interfacing devices. This requires data taken at independent locations to be time aligned. Protection functions responding to signal magnitudes, such as overcurrent or undervoltage, do not require time alignment. But a vast majority of functions would not operate properly if their input signals were not time aligned. For example, a distance function requires voltages and currents to be aligned; a synchro-check function requires the two compared voltages to have a common reference; transformer differential calls for all the used currents to be time aligned as well, etc.

Today, the requirement of time alignment is achieved by synchronous sampling of all input signals of a relay inside the IED itself. This idea could be carried forward only if a given merging unit processes all signals required by a given IED. This would basically create one-to-one correspondence between merging units and IEDs, and poses a question of why not combine the merging units with the IED, yielding a new type of IED that works with analog, fiber-based inputs produced by high voltage sensors of non-traditional CTs/VTs.

The operation of time alignment can be understood either as “hard” synchronization with respect to time, or “soft” synchronization of devices with respect to one another. It could be implemented as precise time stamping of otherwise asynchronously taken samples, or taking samples of all signals exactly at the same time instant.

In either case, availability of protection is dependent on synchronization. This is a vital, often overlooked issue impacting the system architecture and overall reliability of the scheme. In fact, this is one of the central technical challenges that need to be resolved to effectively implement the process bus concept.

The recipient devices must be designed to cope with lost data and potentially variable time latencies for packets coming from different sources. Complexity of existing line current differential schemes is a good extrapolation of the technical challenges in this area. The IEC standard does have cognizance of this issue and does require the manufacturer compensate for filter delays but the implementation details are left to the manufacturer.

The start up procedure when the device wakes up and start communicating while synchronizing itself is particularly exigent, especially if the involved pieces of equipment come from different vendors.

A protection scheme based on external source of synchronization depends entirely on availability and quality of such synchronization source. In the reliability model, this source is connected in series with the other elements and substantially impacts the overall reliability of the system. In order to avoid diminishing the reliability such a source would inevitably have to be duplicated. Duplicating the synchronization clock is not a trivial task as the two clocks will have to maintain mutual synchronism so that when one of them fails and recovers, the system rides through such conditions without a glitch. Additionally, loss of synchronization of one clock with the GPS satellites while the other is still connected needs to be addressed.

The IEC 61850 concept addresses the issue of time accuracy and defines five different levels of time accuracy. The Standard permits usage of SNTP for time synchronization over network for time stamping for SCADA purposes. The SNTP method, capable of reaching about 1ms accuracy, is not precise enough for samples of currents and voltages and the Standard does not offer solutions as to how to achieve the required accuracy. Options to be considered are: an externally provided IRIG-B synchronization signal; a precise, network-based open standard such as the IEEE 1588; or a proprietary network based protocol.

It seems that complying with the high-accuracy time specifications of IEC 61850 requires using an external synchronization source, i.e. IRIG-B inputs. This in turn, requires delivering (redundant) time signal(-s) to all devices that need to be synchronized. Such signals must be driven from two independent (redundant), but mutually-synchronized clocks (contradictory to some extent). If these clocks are driven from the GPS receivers to provide for absolute time reference, issues arise when the GPS signal is lost and recovered. Obviously the protection system does not require absolute time to work properly (except some applications of line current differential relays), and should function normally without the GPS signal. If the GPS signal is lost and subsequently recovered, the redundant clocks will have two, partially contradictory control goals: catch up to the actual absolute time, and prevent any time jumps for the devices synchronized using the timing lines. This adds unnecessary complexity into the system.

Alternatively, the two clocks (either IRIG-B or network-based) do not have to be synchronized, but would switch-over should one of them fail. Again the process of switching over will have to be well designed in order to provide for a robust and safe solution. The IEC 61850 assumes the synchronizing and synchronized devices to be independent pieces of equipment, typically design by different vendors and still work flawlessly for this mission-critical system.

Some IED manufacturers are probing the idea of using the IEEE 1588 network time synchronization protocol for the process bus applications. This creates problems for interoperability – all devices would have to adopt this method, or use their own alternative method of synchronization. If the latter concept is adopted, the user is affected by extra complexity and vendor-specific solutions. Also, one needs to make sure devices non-compliant with the IEEE 1588, are not inadvertently affected by the embedded, network based time synchronization protocol. The IEEE 1588 method requires Ethernet switches to support it, and in today's technology, this creates extra cost for the switch manufacturers.

Another theoretically possible alternative is to use a solution in which all devices on the network synchronize slowly to each other (no master or absolute time) using a phase lock loop approach and large inertia of their internal clocks. This may be an excellent solution for an isolated deterministic network of 2 or 3 devices, but would not work well in a large non-deterministic network with tens or hundreds of devices. Not to mention that such a method is not mandated by the IEC 61850 Standard as a universal, compliant way of time synchronization for the process bus, and will have to remain proprietary.

Presently the issue of time synchronization is solved internally to an IED. Reliability of the technical solution is already included in the overall Mean Time To Failure (MTTF) of the device. The user does not need to engineer or maintain any protection-grade time synchronization means. And availability of protection is not subject to availability and quality of external time sources. It would be beneficial if these attributes were retained in new protection architectures.

The minimum requirement for time alignment in the protection realm is to align signals within a given zone of protection. Moreover, only relative alignment is needed. Given the response time of protective relays, this calls for relative time stamping with an arbitrary time index that could roll over after one or two power cycles. This could be achieved in much simpler ways compared with a generic, hard synch off all devices in the substation to a source of absolute time.

In the implementation of the Process Bus (part 9-2), the Standard has the option of either a relative time stamp or an absolute time stamp. In this application, a full absolute time stamp of 64 bits is typically unnecessary information but is required if the information is to be used as part of a Synchrophasor calculation. In the initial implementation agreement, only a relative time stamp, based on the Fraction of Second, is used. When applying this information to Synchrophasors, information on leap second (one full second can be added or deleted by the GPS system to adjust to planetary rotation) and time quality is also required. Additionally, when correlating sample data between multiple merging units (especially between substations), complete absolute time information and time quality will be required. Careful engineering decisions on how to accomplish this will be needed as the Standard moves forward. The full timing information is not required by protection, but if embedded it could cause harm by revealing weaknesses in the applied IEDs, and the need for extra testing.

4.7 Reliability and Availability of Protection

Availability and reliability of protection are not impacted when using microprocessor-based protective relays as known today, and applied to both protection and control within the SCADA realm of the IEC 61850.

When pursuing distributed architectures based on the concept of a process bus with the intent of eliminating copper wiring in the yard and replacing it with fiber optics solution, availability and reliability of protection is a fundamental consideration, and one of the key barriers to overcome.

For example, consider Figure 6 showing a benchmark substation of Figure A-1, and focus on AC signals associated with protection IEDs around breakers CB-1 and CB-2. This example pictures realistically the concepts of overlapping zones of protection, redundancy and separation of the A&B systems (for simplicity lockout relays are neglected, just two trip coils are shown, the breaker fail devices are separate from the zone relays and are not redundant). The figure clearly illustrates the reason for extensive field wiring: redundancy and overlapping protection zones.

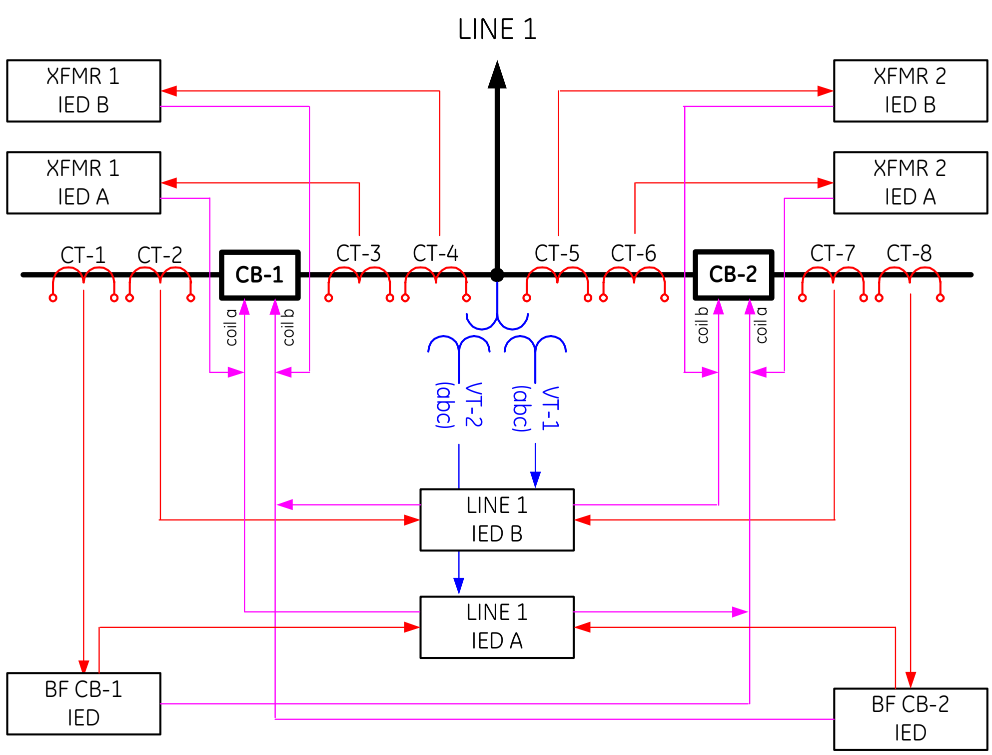
Figure 7 presents a hypothetical architecture in which each AC signal is digitized by a separate merging unit. Separate MUs are used to provide for the DC signal interface (MU-11 through 14). The A&B systems are kept separate. Consider the availability of the LINE 1 protection system A. This zone depends on availability of MUs 1, 8, 10 for measurement and MUs 11 and 14 for tripping, Ethernet LAN A for communications, and Line IED for overall processing - not to mention the time synchronization source for the AC related MUs (1,8 and 10). Composed out of seven of today's IEDs such a line protection system would have an MTTF on an order of magnitude lower compared with today's relays (see Annex B).

Figure 8 presents a sample architecture with one breaker IED (MU) that interfaces two currents and DC signals. Now only two MUS per breaker are required. Still the line protection is a system involving five IEDs (MUs 1, 3, 6, Ethernet switch, IED). Note that the BF function depends on three devices (MU-1, LAN A, BF IED). This becomes a flaw that reduces dramatically availability of the BF function, and calls for solutions in a form of redundant hardware, or equivalent.

Figure 9 further eliminates MUs 5 and 6 by wiring the voltage signals to MU-3 and 4 (typically a relatively short distance compared with the distance from the yard all the way to the control house). Still the line protection depends on four IEDs or five counting the time synchronization source. As explained in Annex B, the expected reliability of the scheme is not there. Besides – MUs 3 and 4 become equivalent to today's microprocessor-based relays in complexity. They support current and voltage inputs as well as digital inputs and output contacts. The question arises: why not provide the complete functionality in such a yard device, eliminating the need for all the other IEDs. The obvious acceptance and maintenance issues may be easier to overcome compared with the solutions of Figures 6 through 9.

It is strongly recommended that concepts building around the process bus and substituting copper with fiber, particularly for the yard wiring, are presented in the context of actual count of CT, VTs, giving consideration to overlapping protection zones, redundancy and separation of the A&B systems. Once the

Fig. 6.
Selected breaker from the benchmark of Figure A-1.



architecture is presented, an IED count can be approximated, and reliability study should be conducted in order to validate the solution.

Annex B calculates Mean Time To Failure values for several hypothetical systems based on the process bus concept assuming arbitrary MTTF data for the system components. It could be seen that the MTTF calculations drive a certain vision of a distributed protection system.

Annex B proves what is intuitively obvious: a process bus protection system set up with off-the-shelf components (merging units fed from non-conventional instrument transformers, explicitly synchronized via their IRIG-B inputs, and communicating via Ethernet network) would have reliability numbers decimated by an order of magnitude compared

Fig. 7.
A hypothetical process bus architecture for the system of Fig.6.

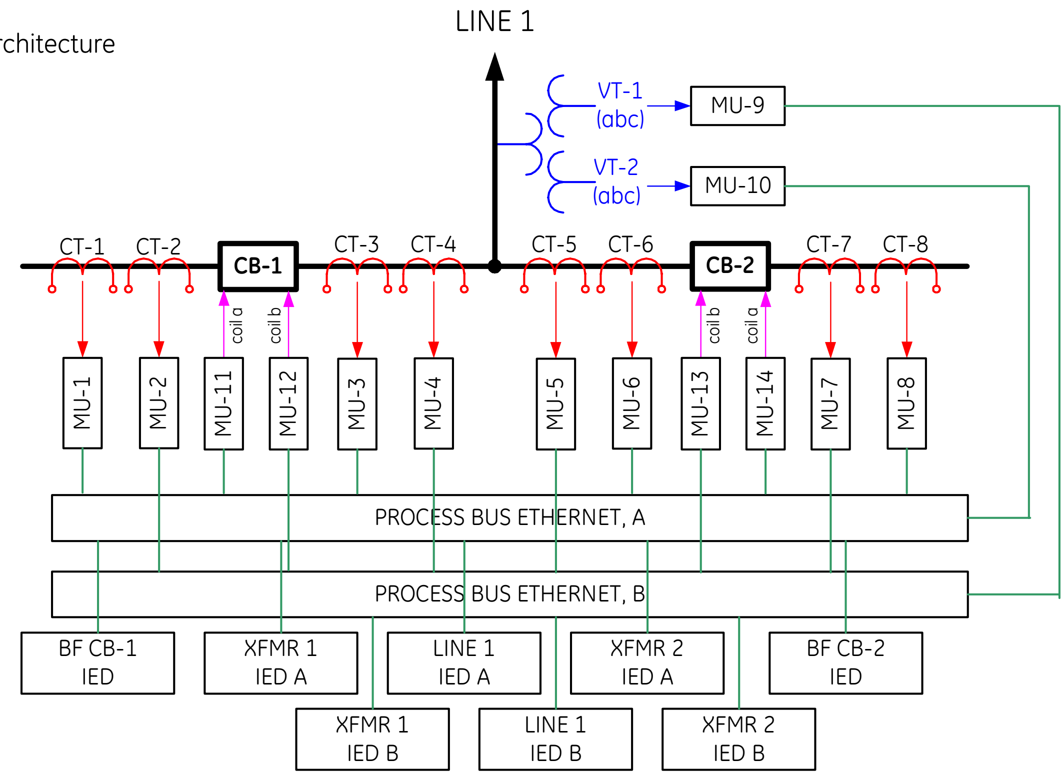


Fig. 8.
A hypothetical process bus architecture for the system of Fig.6.

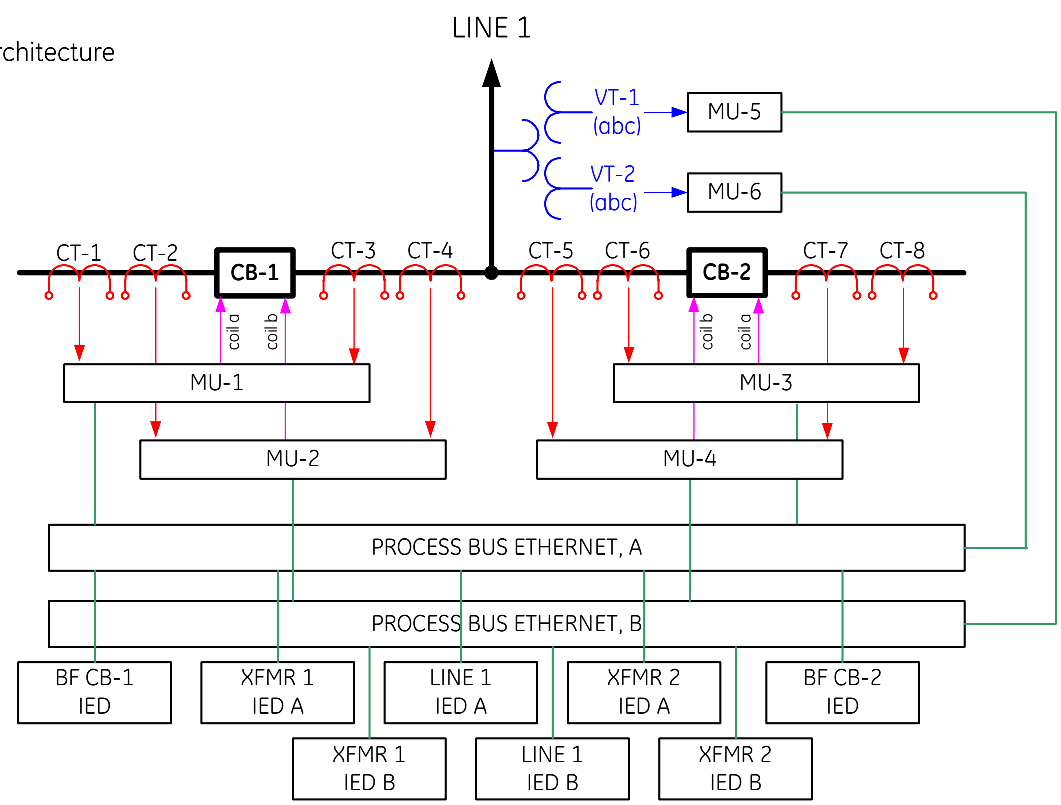
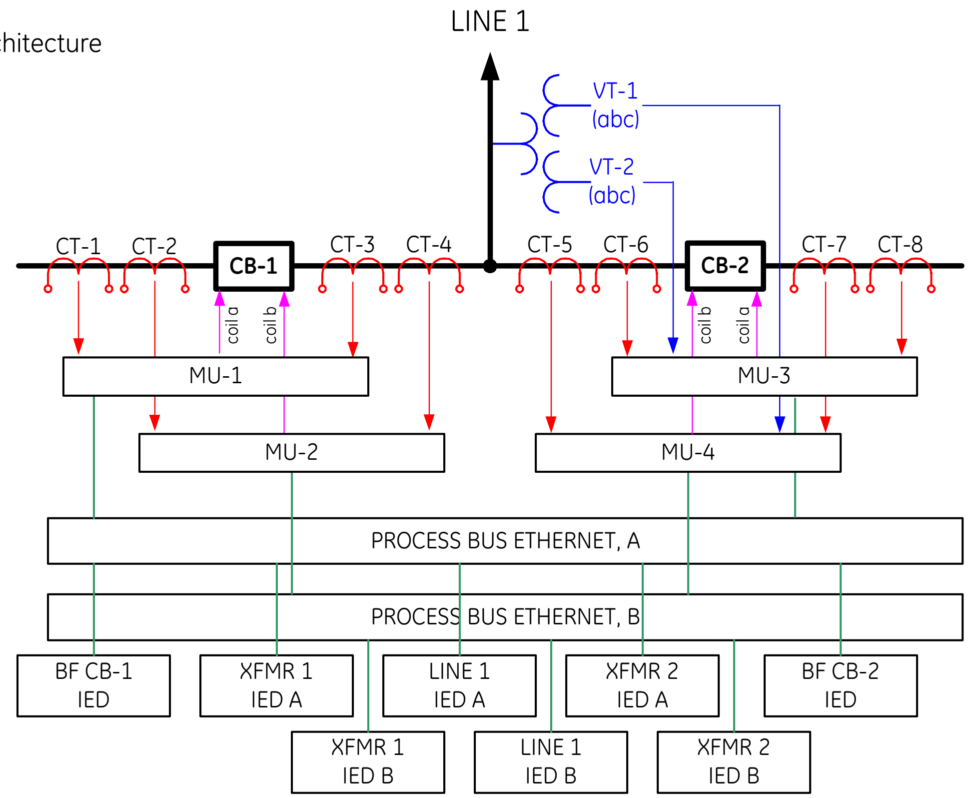


Fig. 9.
A hypothetical process bus architecture for the system of Fig.6.



with today's microprocessor-based relays. This is because of substantial increase in the total part count and complexity of such a distributed system as compared with today's integrated microprocessor-based relays. A successful system for replacing copper wires with fiber optics would have to keep the total part count and complexity at the level of today's relays.

There are challenges in designing such a system primarily time synchronization, and sharing data from merging units to multiple IEDs without an explicit network, while keeping the total count of merging units (interfacing devices) at a reasonable level.

It is justified to assume relay vendors have already conceptualized or are working on the solutions. It is quite obvious that the interoperability protocols of the IEC 61850 in the areas of process bus and peer-to-peer communication are of little help in solving this architectural/reliability puzzle.

4.8 Overall System Performance

Another unanswered question is that of determining and verifying the overall level of performance of a set of interoperating IEC 61850-based devices as a complete system. Although the 61850 Standard does classify the performance of an individual IED with respect to the required response times for individual message types (as would be determined in a benchmark conformance test of an individual IED), there is currently no guidance available on how to characterize message delivery performance across a whole integrated system. As an example, consider an integrated P&C system for a 230 kV transmission substation with say 12 circuit breakers. There are currently no simple and easy to apply design metrics that would allow the designer to determine on paper in advance if the integrated design as a complete system will actually work for this particular topology or architecture. Based on current practice, the system would very likely have to be pre-assembled in a factory or lab setting and undergo a series of complicated tests before delivery to site.

The question remains as to how would the same exercise be repeated in say five years when the in-service station needs to be expanded to 16 breakers? This ad-hoc type of process would be very expensive if it had to be repeated for each and every project, with no quantifiable guarantees of overall performance, especially for protection-critical trip and initiation signals. The cost and difficulty of executing these tests might also inadvertently place an artificial limit on creative design because each novel idea could undermine the experience base developed around a previously known configuration, creating a disincentive to its adoption.

Practical system level application advice is totally missing. It is therefore essential that simple, easy to apply and consistent IEC 61850 design rules be developed so users can determine with certainty that a collection of W IEDs from X manufacturers configured in one of Y topologies will work for a switchyard of up to Z power system elements.

4.9 Failure Management

System integrity and failure management is another unanswered question. Consider for example, the portion of an integrated system consisting of a bus protection that trips say 10 breakers via 10 individual breaker IEDs. These same breakers' IEDs are also shared with breaker failure and reclosing functions as well as providing the interface for SCADA operational control and telemetry. Now consider that one of the 10 breaker IEDs has failed because, for example, its communications interface has been interrupted. All of the applications requiring that IED and its functions have now been disabled. There are many possible consequences, depending on how the system is designed. For example, the system could be 100% redundant and the loss of any one element isn't critical as long as its condition is alarmed. Parts of the system might not be redundant, for example SCADA, so the missing element does constitute a critical failure. Elements needing the missing IED could also revert to an alternate device upon detection of loss of communications.

There are obviously many ways to treat such a failure. The next question is how to safely and consistently isolate the failed device to permit troubleshooting and replacement? How would the maintainer quickly acquire the knowledge of what logical associations are involved with the failed device and the impact of each? What test and maintenance tools would be required to perform this work? At present, no uniform system level functional object definitions or concepts have been defined to cover these types of issues involving the contingency status and operation of an integrated IEC 61850-based substation.

The definition of such concepts and the appropriate software to effectively use them are essential. This will enable users to take advantage of a consistent set of tools and procedures without risking an accident or inadvertent trip to the power system. As we explained in 4.5 above, those users also can and must learn the behavior and characteristics of Ethernet communications links and networking devices to diagnose and safely repair failures.

4.10 Application Gaps

Quite often implementing existing functions using communication-based solutions is not trivial and requires substantial amount of engineering and testing. Once the solution is found, users realize that the proper way of achieving the functionality would have been via standardized functions and services, and not via user programmable logic.

This section illustrates this problem better by presenting issues and solutions related to the lockout functionality implemented in software, as a distributed function, when replacing physical lockout relays and eliminating the associated wiring.

Utilities usually lock out the breakers surrounding a permanent equipment failure. This is done for internal transformer faults, bus faults and failures of breakers. One or more protection devices may initiate operation of a lockout relay (ANSI 86). This is a bi-stable device that remains in the operated state after reset of the initiating protection. The lockout relay provides sustained tripping commands to all of the breakers making up the zone and blocks all the possible means of closing said breakers. The intent is to prevent re-energization of the equipment until a local inspection has been carried out. Accordingly, the lockout relay is usually hand-reset. Due to its simplicity, the lockout has a high reliability. Monitoring of the lockout coil (either by placing a lamp in parallel with the initiating device or through the use of a coil monitoring relay) further increases the availability.

Lockout relays often trip extended zones made up of several breakers. As such, moving this function into the digital domain presents a significant opportunity to reduce device count and wiring complexity. For this analysis assume that transformer bank-1 of Annex A, Figure A-1 is to be protected. A fault requires locking-out of CB-1, CB-2, CB-5, and CB-6.

The basic functional requirements for lockout, whether electromechanical or IEC 61850 based, are:

- Initiation method
- Distribution to multiple relays that control affected breakers
- Presentation to local and remote operators
- Lockout-clearing protocol or standard operating procedure
- Non-volatility
- Independent handling of multiple lockouts on the same breaker (e.g. transformer fault followed by BF)
- Data exchange between substation control and relays.

Two scenarios are considered: (A) a transformer zone IED and dedicated breaker IEDs and (B) CB-5 & CB-6 breaker functions merged into the transformer zone IED and the remaining breaker functions merged into the line zone IEDs. Implementation of the lockout function is shown in Figure 10.

The latches, residing in each IED, together with the messaging passed over the station bus constitutes a "distributed" lockout function. The latches should be non-volatile and located in the IED that is connected to the breaker in order to ensure that the signal is maintained should there be a communications failure. The location of the manual reset may be at the transformer zone IED as shown or may be located at a central HMI. The latter may seem as a violation of the very nature of the lockout, but with advancements in remote inspection (cameras, access to measurements and records), it may become an acceptable solution.

The logic as shown assumes a non-redundant system where the only path for control is through the IED. If the IED responsible for tripping and closing fails, its contacts will reset. However, since there are no other paths for control, the rules for lockout are not violated.

If redundancy is required (as it often is) then the scheme must be modified. Assume that the logic of Figure 10 is implemented in two sets of IEDs (denoted system A & B for this exercise). One possible solution is to use IEDs with bi-stable output contacts for tripping and close supervision. IEDs with outputs of this type are available but are not common. The block-close signal from each scheme would be combined externally with the close commands; leading to increased wiring complexity. This solution raises a new dilemma: It is not possible to reset the lockout if the IED fails after operating (not a problem with conventional lockouts).

Another solution is to cross connect the lockout function of each system. The A & B Transformer IEDs would each operate both the A & B lockouts. The presumption in this case, is that the station busses of each system are interconnected. For some this may be seen to be decreasing the overall reliability of the system since it's conceivable that a communications problem could cause a failure of both systems. Properly designed network devices should mitigate this risk. In another sense this system may be considered more reliable since it can deal with double-contingency events such as the simultaneous failure of the A transformer IED and the B lockout IED in scenario A.

Note that the logic described above is for a single lockout (transformer zone). Picking CB5, it can be seen that lockout functions for the B1 Bus Zone and CB6, CB8, CB1, & CB3 breaker failure zones must also trip this breaker. Therefore the logic shown in Figure A-1 must be duplicated for each of these zones.

Developing and testing such logic poses a significant problem for an average user. Absence of well-designed application templates for various standard protection elements such as lockout function, tripping using GOOSE, testing GOOSE-based breaker fail initiate signals, etc. is one of the obstacles to wider application of basic peer-to-peer elements of the 61850 Standard.

4.11 Testing and Test Facilities

Another unanswered question with respect to deployment of an all-digital substation is how will commissioning and routine maintenance be performed and what test tools will be required to do it?

As new P&C technologies emerge that use advanced communications and other features to reduce both the number of devices and physical interconnections (wire and cable) it is of paramount concern to consider what form of testing is required and in fact what is the purpose of testing? For example, many well-designed IEDs now incorporate extensive self-testing features which make the likelihood of a spontaneous software change remaining undetected by an internal monitoring task practically nil. However, the IED does not know that the overcurrent setting should have been entered as 500A and not 600A. That is a user mistake that can currently only be caught by external quality assurance procedures. Therefore, initial commissioning of any system will remain an important activity. But what about testing following the initial in-service? The industry and regulatory trend to increase maintenance intervals for IED-based systems is in fact based on self-monitoring capability and when maintenance is actually done, the focus is on checking overall functional performance, such as by doing a live trip test where possible.

There are several key considerations emerging in substation communication-based systems. The first issue is the ability of the user to validate the system will initially work as a whole, if all hard-wired signals are replaced by their digital equivalents. By this it is meant that unless extensive factory acceptance test (FAT) and related simulation testing is performed on the actual site-specific configuration, how will the user know with certainty that, for example, 99 % of the time, all protection trip messages will be received in less that 4 ms and the other 1% of the time they will be received in say 6ms? The answer is that this is not a practical or economical exercise for most companies, due to the difficulty of postulating the explicit worst-case conditions that will break the system during the test, the fact that this test needs to be performed on each and every project, all of which translate into higher cost. It is therefore essential that the overall industry come up with standard performance metrics for all parts of an integrated substation system and specifically

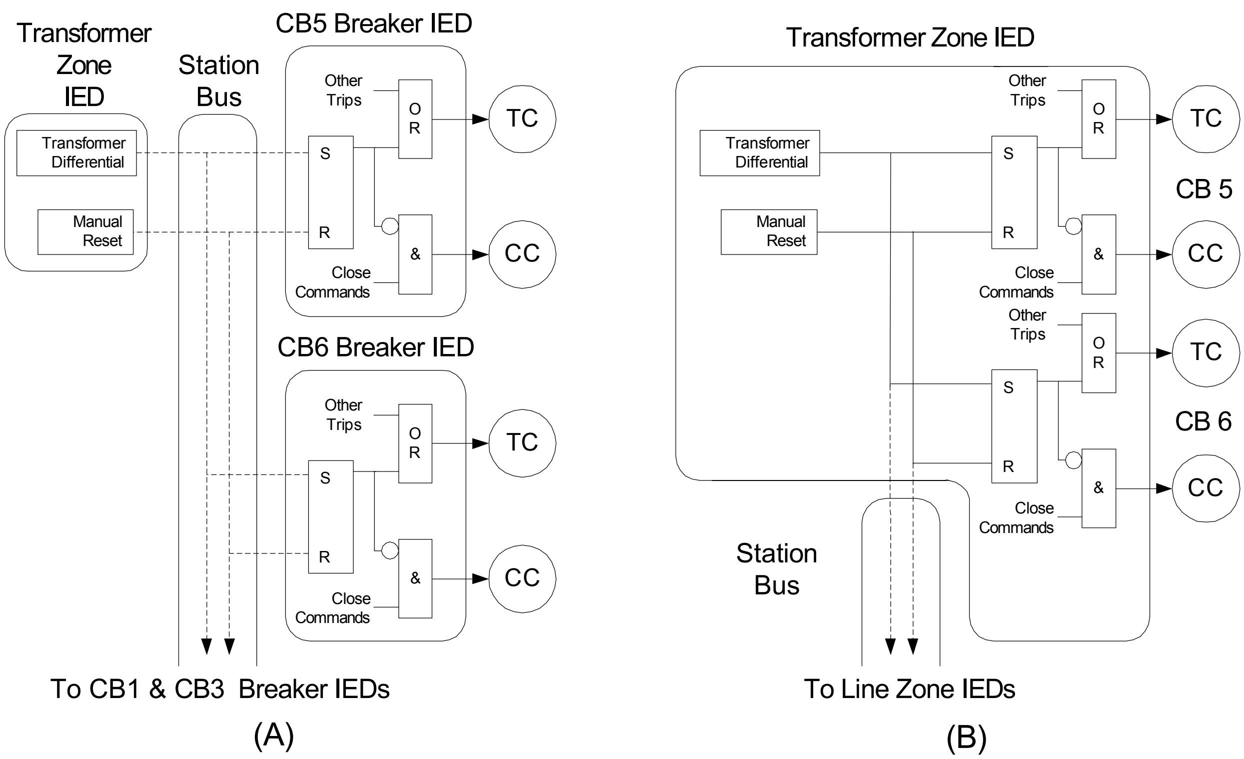


Fig. 10. Possible solution to the lockout functionality.

a way of guaranteeing these metrics on paper for each device type and system architecture. In this way, the user will be able to determine in advance with certainty that any proposed system will work, without having to resort to extensive simulation evaluations. Note that this does not imply that an overall FAT is not required; just that the FAT can concentrate on overall correct device configuration and successful message delivery from point to point, treating all IEDs as “black boxes”, without having to count bits on the LAN.

The second issue concerns the routine isolation of IEDs that are members of an all-digital substation for test and maintenance, assuming that no matter what the technology, sooner or later something will fail. For example, consider an IED that performs a bus protection function and trips six breakers via individual IEDs associated with each breaker. When the maintenance person wishes to block the bus protection, does she block the trip outputs at the bus IED alone, the six destination IEDs, or at all places? What if the six destination IEDs also perform other functions that are not required to be blocked with the bus zone? What if the six interoperable destination IEDs are of a different make and model and therefore use different user interface software? It is therefore clear that standardized test procedures and interfaces are required to enable the user to gain an efficient, accurate overall perspective of the system as a whole. Otherwise, errors and confusion will result.

A third issue concerns the maintenance of the substation LAN as a whole. Although it is assumed that suitably reliable architectures are available, again, sooner or later, some part of the LAN infrastructure will have to be maintained. The implication is that many IEDs, spanning multiple protection zones, could be affected, not only by the communications outage itself, but by the fact that the environment will have to safely support the test and restoration of the affected LAN element itself without disturbing the attached IEDs.

A new category of required test is also emerging as a result of the use of higher level substation communications protocols such as IEC 61850. This test is known as a Compliance Test or Conformance Test and is designed to evaluate the communications performance of an individual IED against a standard benchmark, for all standardized functions claimed to have been implemented. These tests are similar to Type Tests, but the focus is on communications. For example, a device implementing the GOOSE message for protection tripping would be exercised against a standard test system to determine if the response to all applied stimuli is exactly as defined in the Standard. Unlike a Type test, a Conformance Test would not necessarily be able to uncover a flaw in an internal protection algorithm that produces states to be transmitted by the GOOSE message. These tests therefore reflect the extent to which individual devices may interoperate correctly via their communications interfaces. Since these tests involve only one device at a time, these tests are not a measure of how an entire system of devices using the tested protocol will perform, especially in areas such as traffic loading (congestion) effects, optimum use of polled commands vs. unsolicited messages, etc.

Testing of distributed schemes utilizing GOOSE (virtual DC wiring) is a separate problem. Consider a classical case of a breaker fail initiate signal distributed by a bus protection to individual BF IEDs. The 61850 Standard supports the concept of test bits – each transmitted signal can be characterized as real (R) or test (T). Unfortunately, the Standard does not mandate how these attributes are asserted, nor how the receiving devices shall respond to such signals. As a result the user is left to configure those bits manually when needed using programmable logic. When integrating various devices the users will have to examine the hard-coded or programmable response of the involved IEDs to the test bits, and finish the application by writing their own logic to ensure the desired response of the entire scheme.

Overall, the idea of test and response requires more development. One could imagine a concept in which both real and test values are processed in parallel or together so that the real values are available for immediate protection action if required, while the test values facilitate testing. This is technically a challenging task. In order for the user to settle on heavy usage of the test bits, the surrounding functions will have to be hard-coded and guaranteed by the vendor who conforms to the Standard. This is not the case today.

The point here is not to discourage potential IEC 61850 users, but rather to raise some important considerations that need good solid solutions to ensure successful and practical application and acceptance by the largest number of users worldwide. Solutions will and are being developed. In the future, engineers will look upon our present practices as archaic, compared to what they will be employing.

4.12 Human Interfaces

Appropriate HMI capabilities combined with the substation LAN infrastructure will allow the IEDs to be the only devices directly connected to substation equipment. In turn, these HMI functions provide the capability to control and monitor the substation both locally and remotely. Traditional hardwired control switches and associated equipment can be totally eliminated. Therefore, the role of traditional functions that are part of established operational procedures such as physical lockout relays needs to be re-considered in this context. With appropriate functional specification and equipment design, all conventional functions may find a logical equivalence in devices incorporating IEC 61850 communications capability. It is recognized that the path to change may not be easy, especially with long established processes and procedures in place. However, in order to achieve progress, it is paramount that users do not confuse existing solutions to functional requirements with the functional requirements themselves.

Adapting to solutions that take advantage of the IEC 61850 based communications is as much a diplomatic and organizational communications problem than a technical one. As new designs are created, it is critical to involve design and field personnel, since they will need time and understanding to make the transition. Many of them are so steeped in the existing solutions (like pistol-grip control switches, lockout switches, dedicated meters, and separate breaker panels) that they will need time and training to focus on those functional requirements that underlie the existing design, and to accept that they may be able to achieve safe and effective operating procedures with station computer monitor displays, and backup buttons and lights on relay panels. The new design may require human-factors design experts to yield a design that minimizes confusion and risk of error. Few P&C engineers have true human-factors design skills, even though they think they have them.

Flexible HMI capabilities are also emerging that allow, when used with networked devices, a choice of redundant IEDs for primary and backup control, using logic that responds to pre-determined priorities and/or may also automatically switch data channels based on data integrity. This type of application may lead to less expensive and more reliable control architectures where functional duplication can be had for a fraction of the price of past approaches.

It is anticipated that the content of the HMI may expand. Today's coverage includes primary equipment and a very limited amount of information related to the secondary circuits (IED health for example). An integrated substation incorporating any significant replacement of hardwired connections with their digital equivalents should have more sophisticated additional HMI interfaces to allow users to focus on the overall substation at the integrated system level instead of just at the device level. Communication network visualization and monitoring tools are one of the most important aspects. For example, simple to use HMI packages with the necessary underlying functional modules need to be developed to allow quick identification of the overall operational status of all networked IEDs in a station or group of stations. Such a package would be used to recover and display any off-nominal or maintenance-related alarm messages pertaining to the network infrastructure, and its connected devices.

5. Deployment Strategy for IEC 61850

Given the need to develop appropriate system based architectures, tools and procedures for a complete IEC 61850 based substation, the question arises of how to proceed in a managed way so at least some of the benefits of integration may be obtained now.

At present, a very low risk strategy is to utilize IEC 61850 for SCADA applications. Utility grade Ethernet hardware capable of meeting the general response times required for control applications is available off-the-shelf. The end device could be a conventional RTU and conventional operation and maintenance procedures could still apply. Remote retrieval of records (SER, DFR), using the RTU database or an external element such as a gateway to the relay IEDs, is also practical and is the least time critical of any substation application. Data servers with an appropriate power system context are commercially available to implement multi-user systems.

With increasing user demands for remote access to substation data and the use of generic networking techniques, security also becomes an important issue. Again, adequate technology is available off-the-shelf to implement measures appropriate to an IEC 61850 substation.

With suitable adaptation of operation and maintenance procedures, a migration towards the shared use of protection IEDs incorporating control functions can also be easily achieved now. IEDs that support the necessary functionality and logic are already commercially available. The biggest stumbling block to this approach is not technical at all but is due to the rather long and independent design traditions of these two disciplines. In fact, it is only in the last 10 years or so that protective relays with appropriate system integration capabilities, logic and processing power to achieve this application synergy became available. Many utilities and their suppliers have previously supported the two separate disciplines with legions of specialist staff. Protection and control systems had extremely simple interfaces, usually limited to relay contacts, so designers did not need to know a great deal about the internal intricacies of their counterparts' systems. The challenge is now to recognize the economic and technical opportunities made possible through system integration of all-microprocessor based devices and make appropriate opportunities for staff training and familiarity to make this synergy happen.

The next level of technical achievement is that of carrying time-critical protection trip and initiation signals through the substation LAN and/or process bus. For this to take place, appropriate design performance metrics, along with suitable system level test and maintenance tools and procedures, need to be developed. The ultimate stage is the complete replacement of physically wired ac signals with sampled value data carried digitally. Again, procedural development is required. Both of these concepts will also need the collective approval of the utility industry and its regulators. Such approval may only be obtained through sound engineering specifications and designs, combined with appropriate experience gained through proof of concept projects.

The 61850 Standard requires ten large sections just to define objects and communications services and stacks that support the dramatically new substation design approaches described in this and other application papers. The long development time of the Standard itself (since 1995), and the very gradual introduction of products now leaves users with little practical experience on which to lean so far, even though major and significant 61850 substation projects are now under construction or commissioning. It should be noted that those who implemented UCA based solution do have a foundation on which to build. Overall, how to succeed with 61850 is still a question not answered by the contents of the Standard but only through experience with implementation.

6. Functioning in the IEC 61850 Environment

6.1 Configuration Management

The 61850 Standard presents the opportunity to migrate the

GE Consumer & Industrial
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IEC 61850

GE Multilin first to market and the only vendor with IEC 61850 across all protection and control applications.

- **IEC 61850 across a full product line . . . the Universal Relay**
- **Embedded IEC 61850 . . . no external Protocol converters**
- **Builds on 7 years of GE Multilin leadership in open communication standards**
- **Easy upgrades as new IEC 61850 features become available**

IEC 61850 is the new international standard for information exchange and interoperability between intelligent devices within a substation. IEC 61850 lowers the costs and simplifies the engineering, commissioning, operating, and maintenance associated with substation protection and control applications. GE Multilin, the industry leader in open communication standards for protection relays, is best positioned to fully capitalize on the benefits of IEC 61850 through the flexibility, scalability, and common platform of the Universal Relay family.

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  . . . Less cost, more value . . . just the right options for your application
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  . . . Easy expansion, upgrade and service . . . no stranded investments
- Remote and local dual-layer security authentication avoids unauthorized access
  . . . Best in class and beyond security requirements
- Secure Sub-cycle tripping time to protect critical assets
  . . . Increased system loading, stability and security
- True convergence of multiple devices in one platform
  . . . Reduced external devices, wiring, engineering, commissioning, maintenance and capital costs

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large majority of the engineering effort into the configuration of devices. Software tools are envisioned to address almost every aspect of the design process. Existing discussion on the 61850 is almost entirely focused on the design phase – very little attention is given to the post-commissioning activities. The following items are important for effective development as well as management of the 61850-based P&C systems.

Visualization – An important characteristic of 61850 is the free allocation of sub-functions (logical nodes) to any physical device. This introduces the potential for more variability in the IED configuration than was found in pre-61850 devices. As a consequence it is important that new tools present the design in an unambiguous way. Graphical capabilities will aid in this as will the capability to isolate single functions as they might extend across several physical devices.

Collaboration – It is likely that several engineering entities may concurrently develop functions that will reside in the same IED. As such there will be a need for mechanisms that facilitate this. The ability to lock the configuration file or portions of it against editing seems a must. Built-in archiving, revision control and revision history will also be required.

Documentation – Ideally, project documentation should be automatically generated once the initial configuration or modification process is complete. Among other things, this documentation should include all of the information necessary for daily operation of the substation including: descriptions of alarms and their derivations, and interlocking of devices.

Compatibility – Much of the IED configuration will continue to be carried out in the IED configuration tool. For parameters that could be considered as automation-related, there should be no confusion as to where that parameter is configured (in the IED tool or substation configuration tool). Configuration tools should also be capable of importing and exporting relevant data to substation wiring software (CAD) and EMS configuration tools.

Integrity & Security – With more configuration data migrated from hard-wired connections into software parameters, integrity and security of configuration becomes very critical. The vision of 61850 is aimed at fast and easy configuration and modification of the setup. This implies a danger of fast and easy unintended modifications. Archiving at multiple independent data storage centers, strict revision control, strict access, automated compare functions run on the entire configuration and producing change reports for peer reviews are just examples of the new functions that will have to emerge for safe operation of the 61850-based solution.

A fundamental question to be asked with respect to such all-encompassing and heavily relied on substation-level tools is about the market forces eventually yielding mature products. It is obvious that the promised tools aimed at eliminating substantial amount of manual engineering work will have to be quite sophisticated. Given the relatively low volume demand from the power industry, the maturity curve for such tools is questionable.

On the other hand such tools will have to be fully trusted or will not be used at all. Too much is at stake when critical interactions between protection devices such as trip commands or breaker fail initiate signals are established in software. When altering such signals in a today's hard-wired world, many users re-commission the scheme. Equivalent procedures for reconfigurations done in software will have to be established. This needs to cover both the merit of the change as well as the tools used to implement the change. In today's world the tools are low-tech and are not considered as a factor (hard-wired connections or UCA GOOSE configured by a simple IED level tools).

The substation-level configuration tool is a central piece of software interfacing with multiple software or devices via various files or direct on-line services. This brings the issue of software versions of all the interacting tools, and guaranteed interoperability of the tools each time one of the vendors issues an upgraded version or a patch.

6.2 Firmware Management

Firmware change management is a real and important problem today. The industry is taking the first steps in working out rules for vendor-user interaction in terms of notification of found problems, notification of new firmware versions, advise related to risk of using versions with identified flaws, workarounds versus firmware upgrades, advise regarding amount of re-engineering, re-testing and re-commissioning after upgrading to a new revision, etc [36].

Architectures built upon several IEDs each running an independent firmware, exaggerate this problem exponentially in proportion to the number of independent pieces of firmware.

Assume a stand-alone merging unit is used by several IEDs, and a critical problem is identified in the former forcing its firmware upgrade. Should the firmware change of the merging unit trigger re-testing or re-commissioning of all the IEDs?

Or assume an Ethernet switch requires firmware upgrade to take advantage of new features in the area of message priority queuing, or self-healing capacities (rapid spanning tree). How does one ensure that this upgrade does not affect operation of protection schemes that utilize this particular switch? How does one easily verify that the message priority scheme of the switch works properly after the upgrade?

Obviously these questions apply already to some substation applications, but typically not to the mission-critical protection functions. In the 61850 implied architectures users will face such questions when operating P&C systems that apply high level of integration among truly independent devices (multiple firmware) with not enough segregation into detached portions (interaction between firmware). Note that the high-level goals of the next generation P&C system do not explicitly call for using independent devices from multiple vendors. The goal can be achieved without multiplying the number of interacting pieces of firmware: either by reducing the number of independent instances of firmware or by reducing interactions between them.

The 61850's answer to the problem is outlined in Part 10 of the Standard, and is based on standardized interoperability testing. It is assumed that compliance of a given device with the "golden sample" of test procedures and scripts, guarantees automatically unchanged performance in the real-life environment and applications.

Three issues can be identified with respect to this approach.

First, a large number of permutations are to be covered while testing for conformance. To certify a device for any possible application, one would have to exercise substantial amount of combinations resulting from various applications and their possible configurations, variability in the interacting external equipment during the test, reference conditions in the areas of networking (other data traffic), or power system response (avalanche models). Such testing would be extensive, require considerable time and effort, and thus generate an extra cost. Self-certification by a vendor – as a possible solution to the time and cost implications – is of little value strictly speaking. An independent certification/re-certification is a new step compared with today's practice and would have to be factored into the cost and project completion time equations.

Second, independent certification testing of building blocks does not necessarily guarantee proper response of the large system. One reason for this is that the fact of compliance has already many shades. Tens of technical issues ("T-issues") have been already identified in the body of the 61850 Standard. An electronic on-line data-base has been created to catalog and manage those errors, ambiguous items, or proposed enhancements. Assume 100 T-issues being active. In theory each conformance certificate shall list all T-issues and spell out compliance with respect to every single one, in order to provide complete information regarding the test subject. This, in theory would result in 2^100 shades of compliance (1.2677 10^{30}). In practice the situation is obviously simpler as any given application limits the relevance of any particular T-issue. The task of tracking and sorting out the relevant and not relevant compliance items remains, however, in front of the user. It seems that by design, at least for some time, compliance with the 61850 is a moving target. This might be acceptable for SCADA applications, but would face acceptance issues in the protection world.

Third, the concept of reference tests has some weakness in it too. The 61850 Standard is a broad collection of rules for communication. Updates, clarifications, and enhancements will be a big part of it for a period of time. In addition, vendors and users are to decide what and how to implement in the areas not mandated by the Standard. This would put the test software and hardware under the constant pressure to evolve in order to catch up with modifications and clarifications of the Standard itself (T-issues) as well as developments in the existing products. As a result, a complex and evolving software (IED under test) is tested against another complex and evolving software (test facility). In the low probability / high impact domain of protective relaying the above scenario will not necessarily be easily acceptable. Again, the above remarks relate to mission-critical protection functions, and not to relatively simple SCADA portion of the 61850 package.

6.3 Routine Testing

Test facilities are required in a P&C system in order to verify that:

- The hardware is healthy.
- The firmware functions as specified.
- The device has been configured correctly.

In the past the interface between relays were hard-wired through test switches that provided convenient points for injecting and monitoring. New schemes that incorporate peer-to-peer signaling over a local area network require equivalent internal points for forcing and monitoring of signals. These should permit the testing without the requirement to change the configuration of the device. Additionally, these points should not be impacted by the IED configuration; implying that they be embedded within hard-coded functions (Figure 11).

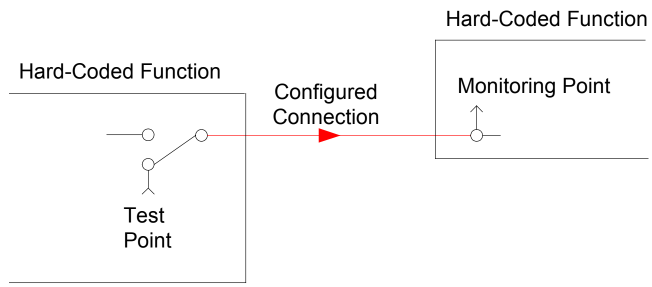

Fig. 11. Embedded test facilities.

Test facilities should also permit testing to be carried out in a staged manner. For example, in a system with redundant A & B protections, one scheme may safely be removed from service while leaving the breakers in-service.

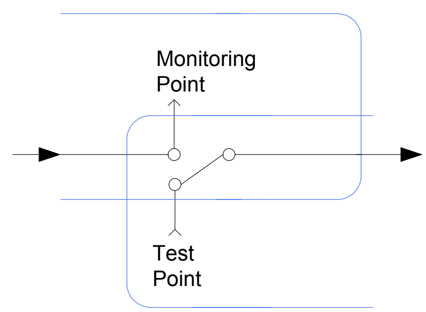

Fig. 12. Overlapping test facilities.

The trip and breaker failure initiate signals are tested up to an open test point. At a later date, a breaker may be removed from service and the remainder of the signaling path can be verified. This capability requires an overlapping of test facilities as shown in Figure 12.

61850 allows for the free allocation of logical nodes to physical devices. Accordingly there is the potential for more variability in the design of the system. As such, the facilities should be flexible enough to permit convenient testing of any scheme.

Traditionally, test switches were physically located adjacent to the associated protection. This was done in order to reduce human errors when operating in live stations. For instance, in the transformer zone example of section 4.10, test switches would be placed between the lockout relay and the outgoing breaker trips. Referring to the distributed lockout logic it is seen that this point now extends into another physical device that may be located on a different panel. A solution to this problem is to send a message to the remote device to indicate that the distributed function has been locally placed in test. The function would operate normally but its outputs would be inhibited.

Finally, a well thought-out user interface should be provided that clearly presents the test state of the device, gives access to internal test points and displays the results of a test. Ideally, the interface should support the development of automated tests and should be interoperable with the latest generation of secondary injection sets. The interface should also be designed to minimize the chance of errors. Solutions such as the ones described need to be examined in detail by authorities who operate and maintain these systems since they have significant impact on the final architecture of the substation automation system.

7. Conclusions and Recommendations

It is clear that the concept of IEC 61850 offers a powerful opportunity to save utilities money through the higher integration and interoperability of historically separated and individually hard-wired systems. Now, significant attention needs to be placed on practical application design, operation and maintenance considerations from the user perspective.

It has become clear to a number of utilities that development has reached the point where it pays to commit to substation design based on IEC 61850 communications. That said, there are still missing pieces, new products announced but yet to be launched, and a host of unanswered questions; with architecture, reliability and application gaps topping the list.

How does a prospective user proceed without undue risk? If the utility is looking at either an all-new (Greenfield) substation project, or a complete replacement of the P&C at an existing station (such as a new drop-in control building), it is relatively easy to make a business case, and to plan on a simple hardware configuration that minimizes wiring and fully utilizes the 61850 opportunity. If one plans on installing such a system, there is no easy fallback to conventional P&C panels, so it is critical to work with vendors and integrators who are willing and able to guarantee that the critical components will be available and tested before the substation commissioning date. Confirm the following when selecting equipment and service vendors:

A. For 61850 LAN-based protection and control with reduced wiring and panel equipment, the most critical 61850 component that must be complete and work correctly is GOOSE/GSSE control messaging, so focus most heavily on the development status of these services in the relays or IEDs to be used. If the design depends on LAN control in lieu of wiring and GOOSE is not working, there is no fallback position.

B. For communications of operational (SCADA/EMS) and non-operational (maintenance, asset management, operations logging and recording, etc.) the station can function either with 61850 object communications, or with older protocols that function on an Ethernet LAN, so there may be temporary or permanent fallback positions for 61850 shortfalls.

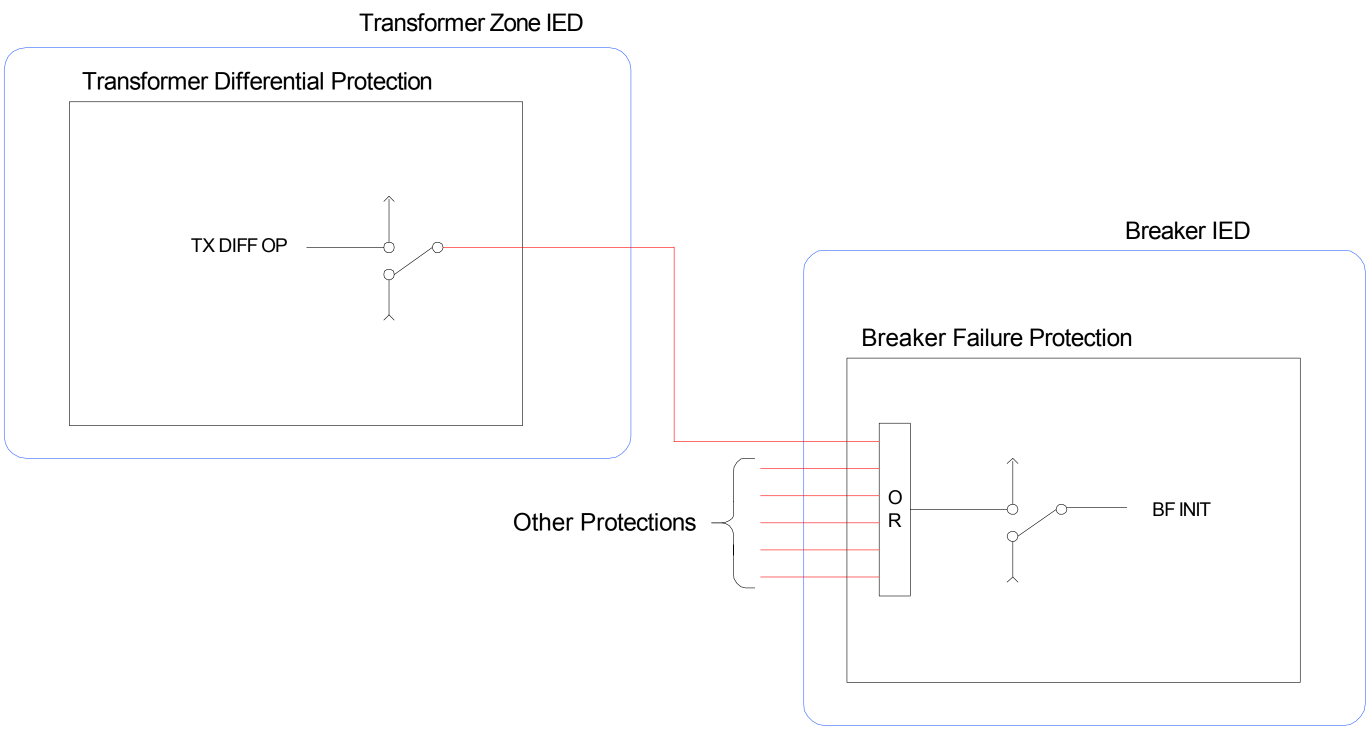

Fig. 13. BFI example.

C. If the vendor is pressed to develop a needed capability and the development schedule seems optimistic or aggressive, identify in advance what a fallback position is (e.g., talk to SCADA with DNP3 messages that require manual configuration, rather than with convenient self-configuring and self-describing 61850 objects). Identify a date by which a decision must be made if the fallback implementation is to be available on time. If the new 61850 feature is not ready and proven by that date, carry out the fallback plan and wait for the next station to use the new feature.

D. Keep in mind that communications of 61850 defined objects requires both servers and clients. For example, the selected relays may have a full implementation of 61850 object communications, but the SCADA/EMS concentrator or host device must have the ability to request data it needs according to 61850 methods. The same is true for a local user interface computer.

E. Note that 61850 protocol packets and other types of Ethernet traffic can coexist on the same LAN – there is no requirement that every message be in 61850 format. It is critical to understand and accept this if some services cannot be initially commissioned using 61850.

F. Among the many devices to be integrated at a modern substation, many will certainly not offer 61850 communications yet. 61850-capable relays or relay concentrators are available now. But consider transformer gas-in-oil analyzers, top-oil temperature sensors, weather stations, or capacitor bank controllers – few will have Ethernet communications of any sort, and the protocols will be older standards like Modbus or DNP3. The P&C architecture must provide some network interface devices on the LAN that can convert these older or serial protocol messages to a LAN 61850 or other message format.

G. Use off-the-shelf products, which the vendor has demonstrated at other sites, if available.

H. For new products, obtain management-level guarantees from the supplier that the equipment will be ready for testing and commissioning according to the utility construction and operating schedule, with some concrete consideration to insure delivery and performance.

I. For first-time use of new products, the user can drastically reduce risk by engaging the manufacturer and/or integrator to deal with product settings and communications interfacing issues, and to commission a working system on schedule, as part of the job. If the user buys products and commits to carry out the system integration in-house on this first use, there is high risk of problems and delays for which the vendor may not assume responsibility.

J. The user who wants to introduce a 61850 LAN-based substation P&C system in a conservative utility environment must be a diplomat and be sensitive to the organizational issues caused by change. There must also be an adequate budget for introduction of the new technology. Stakeholders around the organization need to be educated on the benefits of 61850 and the reasons for the design changes. Inputs must be sought and discussed, as the 61850 proponents fight hard to get acceptance of the new design approaches and resist fallback to replication of old designs in new equipment. Field personnel will need serious involvement in changes of their work rules and operating procedures, and must become comfortable with new field troubleshooting tools and techniques. A pilot project of meaningful scale, with participation by the most progressive personnel in the organization, can set the pace for future change.

K. Plan for tools, training, and utility-site simulators as part of the initial projects.

L. Pilot project demonstrations that are not connected to actually do the P&C job (tripping for faults; reporting to SCADA/EMS) tend to fail for lack of attention to detail.

M. At many utilities, the P&C organization is disconnected from or at odds with the utility IT organization, not unlike the split between relaying and SCADA/EMS seen at some utilities scores of years ago. For long-term success, the protection and IT personnel need to reach the mutual respect and understanding that will lead to cross-training and mutual support as substation LANs connect to corporate WANs. Transfer of 61850 and other data to the enterprise to run the business better is an important part of the business case for 61850.

N. A new 61850 based substation will yield massive data on the daily operations and events at the substation. Design work should include planning for efficient transmission, storage, management, and automated processing of this data to improve utility operations, and to avoid overwhelming personnel who were used to older systems with less to report.

O. New 61850 based relays with LAN control have settings or configuration files that define the functionality in the way the panel wiring did in older stations. The user needs a tightly-managed and controlled repository for settings and configuration data, that also ties in product firmware versions and hardware platform issues. The IEEE Power System Relaying Committee is preparing a detailed report on management of relay settings and configuration data. Draft versions are available on-line [35].

Utilities are applying these methods to engineer new, highly integrated P&C installations.

While this list of issues and cautions may seem daunting, any new substation design is a big project and requires clear goal definition, in depth planning, and rigorous management to ensure success.

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Annex A.

Protection and Control Today – Back to Basics

This Annex discusses some of the basics of protection and control as successfully used for decades. Majority of these general requirements will have to be retained by new communication-based solutions. It is important to distinguish between the key need, and the present way of accomplishing the need (current implementations are ways of meeting functional requirements, not the functional requirements themselves). While users will have to re-think and adapt to different ways of accomplishing the basic requirements, architects of the new systems must factor in all the basic principles that constitute the protection and control engineering field.

This Annex touches on several key aspects, and proposes a simple arbitrary benchmark (Figure A-1) for discussing both the principles and new solutions. Too often proposals for communications based protection systems tend to neglect the actual number and location of CTs, disregard the principle of overlapping zones, maintainability, redundancy, and other practical aspects. This paper encourages using benchmarks such as the one in Figure A-1 when presenting new P&C architectures, particularly solutions involving merging units and similar approaches.

A.1 Zones of Protection

The zone of protection refers to that primary equipment for which faults are detected by a given protection scheme. The protection scheme is defined by the relays and their measuring CTs and VTs. Interrupting devices (circuit breakers, circuit switchers, etc.) that are operated by the protection scheme must be arranged remove all sources of energy from within the protection zone. Ideally, a protection zone is confined to a single primary device such as a transformer or a bus. Limitations on the location of instrument transformers and interrupting devices may result in larger zones. Protection zones must overlap in order to provide coverage for all primary equipment. This typically results in breakers falling into multiple zones.

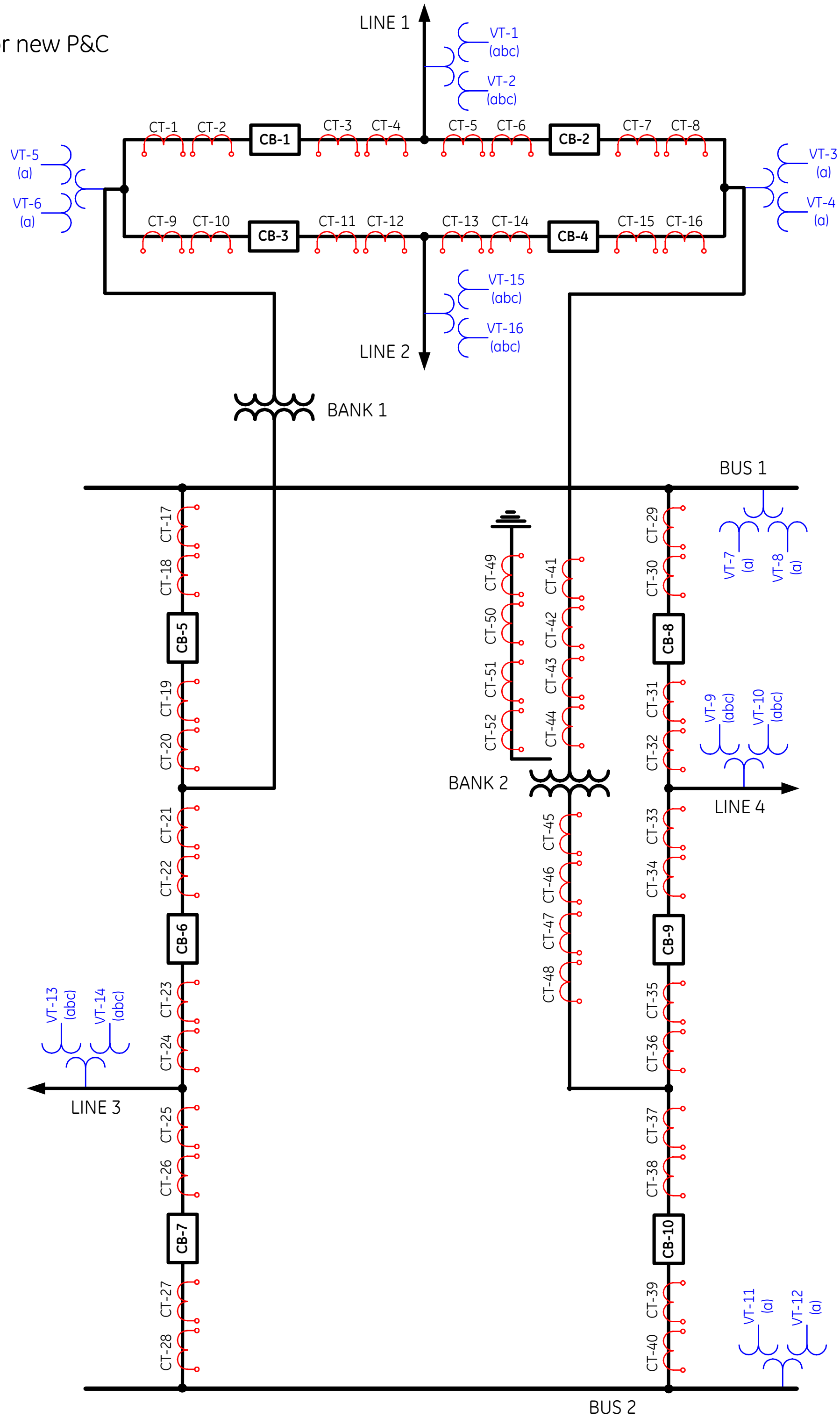
A.2 Allocation of IEDs to Zones of Protection

Typically an IED or relay is dedicated to the protection of a single zone. In this way a failure of this device or its algorithms compromises a single zone. IEDs may provide backup protection to other zones. In this case coordination is often required. When required, redundant IEDs may be assigned to the same zone. Redundancy may also be extended to the DC supplies, measuring CTs, breaker trip coils, relay panels, and cable routings. Redundant IEDs may use different operating principles or be manufactured by different vendors. Redundant protection generally provides increased reliability and shorter clearing time when compared with backup protection at the expense of increased cost and complexity. Redundant protection also allows one IED to be taken from service for maintenance while the primary equipment remains in-service, protected by the other IED.

The requirement to keep primary equipment in-service also affects the topology of the substation itself. For instance 1½ breaker, ring bus, or double bus configurations are often implemented at higher voltage levels. In these cases it may be useful to allocate IEDs to breakers as well as to protection zones. For instance, a 1½ breaker, line terminal may consist of redundant line distance or line differential IEDs protecting the transmission lines and an IED for each of the associated breakers. The breaker IED is responsible for breaker failure, auto-reclosure, synchronized closing and interlocking. In future, the breaker IED could be considered to be the sole interface point for all protection and control functions associated with the breaker, including SCADA.

Routine maintenance can be carried out on each of the redundant line protections (one at a time) with all primary equipment in-service. Additionally each breaker and its associated IED can be taken from service (one at a time) for maintenance purposes.

Fig. A-1.
Possible benchmark case for new P&C architectures.

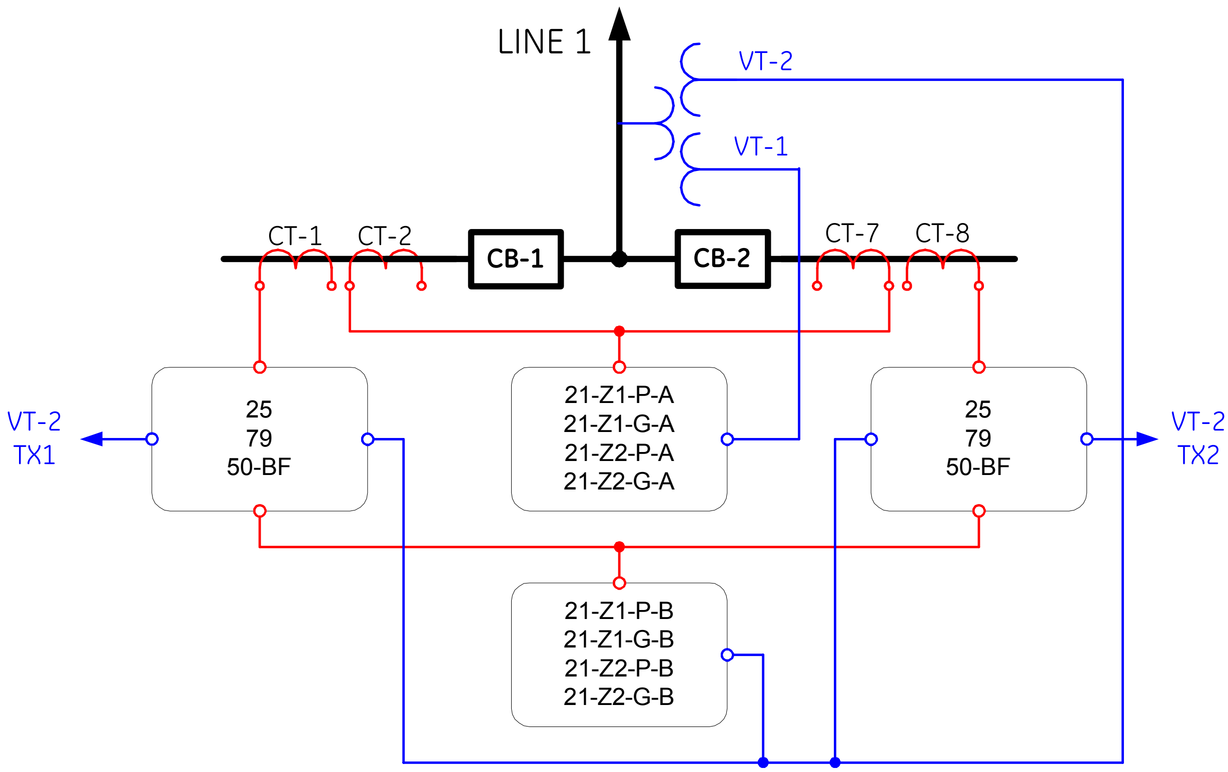


There is a value in separating protection functions and keeping them aligned with the zones of the primary equipment. Some reasons for maintaining this separation are the avoidance of common-mode failures, maintenance of a clear separation of systems under test and to facilitate easy expansion and/or retrofitting the system in modular blocks.

A.3 Allocation of P&C Functions to IEDs

Conventional protection schemes were initially developed using electro-mechanical relays. These devices often performed one or two functions only on a per-phase basis. While these schemes required a lot of panel space and wiring, they also benefited from inherent redundancy. For example, a feeder scheme could consist of three single-phase IOC/TOC relays and a ground IOC/TOC relay. This meant that 2 relays were expected to operate for many fault types (with the exception of a low magnitude ground fault). In microprocessor relays much of this inherent redundancy is lost. As such, when the protection designer is assigning functions to a multifunction device, he/she needs to consider the implications of the loss of all these functions when the IED fails. Conversely, integrating more functions into a single device results in fewer IEDs and a simpler overall design. Historically, functions were separated within one protection group because there was no other choice. Integrating functions within a group doesn't necessarily lessen reliability in a fully-duplicated scheme because common failures have always existed. For example, losing the A-system DC supply breaker, could affect two panels worth of discrete elements just the same as it would affect the functionally identical scheme implemented in one completely integrated IED in a 4N case.

Fig. A-2.
Example of allocating P&C functions to IEDs.



For another example one can consider again the line terminal shown in Figure A-2. Traditionally the functions shown in the breaker IED (synchrocheck, auto-reclose, and breaker failure) were not duplicated. The protection designer may decide to reduce the number of IEDs by merging these functions into one of the line protection IEDs. If so, consideration must be given to the interruption of these functions during routine maintenance. Another consideration is the potentially large tripping exposure to a mal-function. It is probably warranted to duplicate these functions in both IEDs. However, this approach may require careful consideration. For example, allowing two auto-reclose schemes to operate in parallel could lead to unexpected and unwanted behavior especially for single-pole tripping.

A.4 AC Signals

Most protection schemes utilize voltages and currents measured via conventional CTs and VTs. CTs typically have nominal secondary current ratings of 1A or 5A. VTs typically have nominal secondary phase-neutral voltage ratings of 57V to 120V. CTs may serve several IEDs wired in series. If so, the protection designer needs to consider the consequence of a failure of a cable or CT on the overall scheme. Test facilities (see A.6) should also be designed in such a way that an IED may be isolated from the system without interrupting the current to other IEDs. The IEDs of redundant systems are often fed from separate CTs. The cabling may be routed over different paths for additional redundancy. If the redundant IEDs share the same panel, the cabling may then terminate on different sides of the enclosure. VT signals are more likely to be shared by multiple IEDs. If so, fuses are typically installed throughout the circuit. These devices must coordinate in order to ensure that a fault in the voltage circuit impacts as few IEDs as possible. VT fuse fail schemes should supervise protection schemes that are predisposed towards false operation for a failure in the voltage circuit.

Almost all protection applications require their input AC signals to be time-aligned. This calls for synchronization of measurements of these signals, either with respect to one another or with respect to the absolute time. Today, this requirement is achieved by bringing all signals into a single IED and processing them synchronously within the device with respect to an internal arbitrary time scale. With the exception of some line current differential applications, protection functions today do not depend on any external time synchronization source.

A.5 DC Signals

Protection schemes often utilize signals from other schemes or from field devices (circuit breakers, etc.). Contacts are wetted from the station battery to feed auxiliary relay logic or the inputs of IEDs. In large stations, miles of control cabling are sometimes required to route these signals. As such, station batteries are typically ungrounded and are equipped with battery ground detection in order to allow station personnel to detect and repair cable faults. Even so, incorrect status information due to faulty circuitry is inevitable and must be planned for in the design. In general, a protection scheme should not produce a critical response (i.e. trip a breaker) based solely on a status input. For example, in line distance applications, permissive transfer tripping is more secure than direct transfer tripping because the former requires a protection element to pickup simultaneous to receipt of the permissive signal. In applications where this principle cannot be adhered to, the scheme should use multiple status signals for additional security. For example, a scheme that uses both the normally open and normally closed breaker status contacts can be designed to discriminate between correct and abnormal indication.

In the redundant systems the signals for each scheme are usually derived from different devices or field contacts. These signals are segregated onto separate cables. The cables may be routed via different paths within the station. In very critical stations there may be separate batteries for the redundant systems. This reduces the system exposure to battery grounds.

Critical dc signals such as trip, close or breaker failure initiate can be equipped with test facilities to allow safe isolation of those signals from the rest of the system.

A.6 Testing and Test Facilities

Provisions are made in every protection scheme to facilitate commissioning, routine maintenance, and troubleshooting. Switches are often inserted between the measuring VTs and CTs and the IEDs. These serve as points at which the relay can be isolated for troubleshooting or for secondary injection testing. They also serve as measuring points for the secondary currents and voltages. Switches are also often inserted into the DC circuits. These may be used to isolate trip and close commands to breakers. They may also be placed at intermediate points within the protection scheme logic or between protection schemes in order to verify specific functions or logic. Facilities may also be provided by the IEDs themselves in the form of monitoring points, targets, or LEDs. In some cases dedicated schemes are designed using rotary test/normal switches, pushbuttons, and indicating lamps. An example of this is the transmit/receive test facilities associated with the pilot scheme of a line terminal. As protection schemes become more integrated and IED counts go down, there will be a greater need for internal IED test capabilities. Internal facilities must be designed in such a way that the user will have the same degree of confidence in the outcome of the test as was attained with external test facilities. They should also be flexible, user-friendly, and give unambiguous feedback on the state of the test.

In general, it is worth considering the six general categories of tests traditionally applied to existing P&C systems and the reasons for each.

Type Tests are extensive tests usually performed by the manufacturer and are intended to uncover basic flaws in the design of a product or system. Type tests include a full range of performance and environmental tests that subject the equipment under test to the maximum possible stresses it is likely to ever experience in-service. Type tests are also intended to prove that a particular system actually meets its stated functional and performance specifications. A major part of testing digital systems is the verification of software performance under a variety of externally simulated conditions designed to uncover any weaknesses at the specified performance levels. In tests of protective relays, external digital simulators capable of modeling actual power system behavior are used to drive power amplifiers supplying actual signals in the correct range of the CT and VT inputs of the relay under test. In this case, the relay under test is treated as a “black box”. Type tests are generally complicated and expensive to perform and are therefore done only at the time of initial product design and any subsequent major revisions.

Production Tests are tests performed on a regular basis on every unit produced and are intended to uncover variations in product quality due to manufacturing tolerances, assembly errors, etc. Production tests are usually performed by connecting sub-assemblies or the complete unit to a test jig that exercises the system using a pre-determined test script. For example, a communication port might be tested by presenting a series of test messages and looking for certain expected responses within a specified time window and with all transmission parameters within specification. A complete “black box” test (reduced in scope relative to a type test), may be performed at final assembly.

Commissioning Tests (also known as a site acceptance test or SAT) are tests performed during the initial commissioning of a P&C system in the field. Commissioning tests are intended to uncover errors in wiring and other installation errors. Commissioning tests are also used to uncover errors in entering the applied relay settings, for example a circuit breaker trip contact was not linked to the output of a distance zone 1 element, but are not intended to verify the design of the relay internal software itself. This is a point that sometimes uses up much utility time and effort. Once a particular relay has passed its type tests and the design is frozen, the programming and basic performance of all its internal elements cannot subsequently change. The effectiveness of commissioning tests on software is essentially limited to verifying that the user-accessible configuration settings have been entered and function as intended for the particular application. Commissioning tests done in the field per se can not uncover power system calculation errors leading to an incorrect choice of, for example, zone 1 reach setting. Certain consistency checks such as simple rule of thumb calculations are easy to do and may uncover errors in the settings. Commissioning tests are often concluded by performing a live test trip of the protected zone to absolutely ensure that all circuit breakers will trip as intended.

Maintenance Tests are tests performed at routine intervals of typically every four years or more to uncover any deterioration in the overall performance of a P&C system. Historically, maintenance intervals were shorter when P&C systems were largely comprised of electro-mechanical elements that were subject to the effects of dirt, oxidation, heat, etc. However, the advent of digital systems with extensive self-monitoring capabilities has significantly lessened the requirements for routine tests of the P&C system itself. For example, once commissioned and placed in-service, IED self-checks such as memory checksum routines ensure that a digital relay will perform its mission indefinitely without any degradation in the settings configuration possible. Certain parts of the IED, such as the analog to digital converter subsystem, may be subject to small drifts in gain over long periods. Many IEDs also incorporate mechanisms such as standard value tests that are automatically applied on-line, thus essentially eliminating the need to test the A/D converter on a routine basis. In order to take full economic advantage of the capabilities of modern P&C systems, the most important consideration when contemplating a maintenance test is to test only those parts of the overall installation that can actually change while in-service. The parts that can not change unless manually interfered with such as software may generally have the maintenance substantially reduced to a broad overall functional check.

Factory Acceptance Tests (FAT), as the name implies, are tests typically performed in the factory on an overall integrated system, such as a collection of protection IEDs, communication interfaces and control components comprising the complete installation for an entire substation or major sub-division thereof. FATs typically use either standard or customer-specific performance targets and are intended to ensure that the whole assembly will perform as expected in the field. Typical areas considered are I/O loading, buffer capabilities and overflows, communications performance and in some cases, environmental performance. The main difference between a production test and a FAT is that the production test is usually concerned with one item at a time, such as an IED, or individual modules going into an IED; whereas an RTU or equivalent unit is usually a composite of several individual items or modules that are assembled into a cabinet for a project-specific application.

A.7 Lockout Relays

Utilities usually lock out the breakers surrounding a permanent equipment failure. This is done for internal transformer faults, bus faults and failures of breakers. One or more protection devices may initiate operation of a lockout relay (ANSI 86). This is a bi-stable device that remains in the operated state after reset of the initiating protection. The lockout relay provides sustained tripping commands to all of the breakers making up the zone and blocks all the possible means of closing said breakers. The intent is to prevent re-energization of the equipment until a local inspection has been carried out. Accordingly, the lockout relay is usually hand-reset. Due to its simplicity, the lockout has a high reliability. Monitoring of the lockout coil (either by placing a lamp in parallel with the initiating device or through the use of a coil monitoring relay) further increases the availability.

A.8 Human Interfaces

Human interfaces are necessary to provide status on the operational state of the scheme. Often both local and remote indications are required. Targets, LEDs, and annunciator panels capture operational information such as the particular element that has operated, the phases involved, and whether or not reclosure was successful. Status is also provided on the health of the protection scheme; including IED failure, loss of DC, VT fuse failure, and trip coil failure. The interface is typically nonvolatile and capable of capture of fleeting events. The human interface usually permits limited reconfiguration of the protection scheme such as setting group control or blocking of autoreclose. Sequence of event systems (either centralized or integrated to the IED) provide a time stamped record of important occurrences within the substation. Disturbance recorders (either centralized or integral to the IED) capture raw voltage and current waveforms during system faults or other disturbances. This data may be used for operational purposes or to verify the performance of protection systems.

Also, various means of operating the equipment are provided via reliable interfaces such as pushbuttons, pistol-grip switches, etc. These devices are known to the existing work force and extremely reliable.

A.9 Availability of Protection

The reliability of the protection scheme is a function of the reliability of the individual components and the inter-relationship between these components. The earliest protection schemes were built from single function, electromechanical protection & auxiliary relays that were hard-wired for the particular application. Due to the simplicity of the constituent elements, the reliability of these schemes was very high. However, a component failure could go unnoticed until maintenance was carried out or a fault occurred.

A protection scheme of the current generation may consist of a single multifunction IED and its associated wiring. The IED has many more components that the simple devices of the past. Therefore the IED should have a correspondingly higher rate of failure. This disadvantage is offset by the fact that microprocessor-based devices are capable of performing self-diagnostics. In a properly designed system, most IED failures will be quickly identified, the failed component replaced, and the system returned to service in a minimal period of time. The availability of such a scheme can be much better than otherwise anticipated.

As protection schemes continue to evolve our notions on system availability should reflect the underlying components. Redundancy may be added in areas where it was not previously required, however, the total installed cost of the installation could still be much lower than in conventional practice.

With all protection functions allocated between one or two IEDs, availability of such IEDs is directly reflecting on availability of protection for the zone. Typically redundant, independent systems are deployed. Within each system, a zone is protected with the availability of about 100 years of Mean Time To Failure (MTTF). This number is driven by the fact of providing key protection from a single, integrated device. Typically, a failure of such device impacts a single zone of protection, and does not spread into larger portions of systems A or B protection. Similarly, such a device could be intentionally taken out of service, and the affected area is both contained and well defined.

Today's protection functions do not depend on sources of time or communication equipment for extensive peer-to-peer communications. If used, the time synchronization and communication devices are treated as a part of the scheme, and are typically isolated from other zones of protection so that their failures or maintenance have limited impact on the overall substation protection system.

Annex B.

Reliability and Availability Calculations

A Poisson distribution is a reasonable model for the failure of components for a "back of the envelope calculations" [33].

The probability distribution function of the failure of a component is typically assumed as:

$$f(t) = \lambda \cdot e^{-\lambda t} \qquad (1)$$

The probability of a component failing by time t, or the portion of a population of components that will fail by time t, is given by:

$$F(t) = \int_0^t f(\tau) \cdot d\tau = 1 - e^{-\lambda t} \qquad (2)$$

The reliability function, the probability that a component will not fail by time t, is given by:

$$R(t) = 1 - F(t) = e^{-\lambda t} \qquad (3)$$

The Mean Time To Failure is the expected value of the probability distribution:

$$M = \int_0^\infty \tau \cdot f(\tau) \cdot d\tau = \frac{1}{\lambda} \qquad (4)$$

Next, one needs rules for series and parallel composition.

In a series composition, an assembly is built from two components, both of which must work in order for the assembly to work. In a parallel composition, the assembly works if either of the components works.

For series composition of two components, the mean time to failure for the assembly is related to the mean times to failure of the components, M1 and M2, by:

$$M_{series} = \frac{1}{\frac{1}{M_1} + \frac{1}{M_2}} = \frac{M_1 \cdot M_2}{M_1 + M_2} \tag{5}$$

For parallel composition, the relation is:

$$M_{parallel} = M_1 + M_2 - \frac{1}{\frac{1}{M_1} + \frac{1}{M_2}} = M_1 + M_2 - \frac{M_1 \cdot M_2}{M_1 + M_2} \tag{6}$$

Next we turn our attention to availability, which is a separate question from reliability. The question of reliability in the context of this discussion is focused on how long it takes for the system to fail, assuming that the system is not repaired as components fail. On the other hand, availability addresses what percentage of the time the system is operational, and includes temporary outages such as loss of power, noise, and temporary loss of communications.

Each subassembly of the system is characterized by the fraction of the time that it is available:

$$A = \frac{\text{up time}}{\text{total time}} \tag{7}$$

Equivalently, a subassembly can be characterized by the fraction of the time that it is unavailable:

$$D = \frac{\text{down time}}{\text{total time}} = 1 - A \tag{8}$$

Next, we need rules for composition. For a series assembly of two independent components, the availability of the assembly is given by:

$$\begin{aligned} A_{series} &= A_1 \cdot A_2 = (1 - D_1) \cdot (1 - D_2) \approx 1 - D_1 - D_2 \\ D_{series} &= 1 - A_1 \cdot A_2 = 1 - (1 - D_1) \cdot (1 - D_2) \approx D_1 + D_2 \end{aligned} \tag{9}$$

The approximations are valid for small values of D.

For a parallel assembly of two independent components, the availability of the assembly is given by:

$$\begin{aligned} D_{parallel} &= D_1 \cdot D_2 \\ A_{parallel} &= 1 - D_1 \cdot D_2 \end{aligned} \tag{10}$$

It is intuitively obvious, and proved by the above equations, that the reliability of components is generally much higher than the reliability of the system. Therefore, the system will fail much sooner than the expected end of life of any of its components.

Consider a system of Figure B-1a. An IED working as a protection relay receives data via network from three merging units (transformer relay, for example). Each merging unit is synchronized via independent connections from a source of time. Merging units, network, the IED and the synchronization source are designed and manufactured for 150 years of MTTF (1 out of 150 devices fails in a year). All the connections are assumed to have 300 years of MTTF (1 out of 300 connections fails over one year).

In such a system, all components must work in order for the system to work. For such a series assembly, the MTTF is 15.8 years (1 out of 16 systems will fail in a year). This is well below today's standards and will not be accepted by users.

Assume the relative MTTF data for all the components of Figure B-1a remain the same. In order to guarantee 100 years of MTTF for the system, the absolute MTTF values for the components will have to be as in Figure B-1b. For example, the merging units, IED and the network will have to be of 950 years of MTTF, while the connections will have to have a reliability of almost 2,000 years of MTTF. This example is based on arbitrary numbers, but nonetheless illustrates the magnitude of the problem.

Reliability of the system can be improved by eliminating components from the system, providing redundant components, or increasing reliability of individual components. As illustrated in Figure B-1b, the last solution is not a practical one.

Consider alternative architectures shown in Figure B-2.

Figure B-2a assumes the source of synchronization is provided via network. This eliminates connections from the synchronization source to the merging units. There is no redundancy added to this scheme, but the number of components in the system is reduced by two connections (3 removed, 1 added). This increases the system MTTF from 15.8 years to 17.6 years.

Figure B-2b assumes all connections in the scheme to be fully redundant. This implies separate fiber cables and diverse routing of the cables so that the failures are truly independent. Based on equation (6) a redundant component of equal MTTF increases the original MTTF by only 50%. In the case of Figure B-2b, two connections of 300 years of MTTF each yield an assembly of 450 years of MTTF. If so, 1 system of Figure B-2b out of 20 systems would fail within a year (19.6 years of MTTF).

Figure B-2c assumes the synchronization source and the network to be redundant. This brings their arbitrary 150 years of MTTF to 225 years for the system calculations. Now, the architecture of Figure B-2c has the MTTF of 21.4 years.

Figure B-2d eliminates the synchronization source. It is assumed that the host IED is driving synchronization

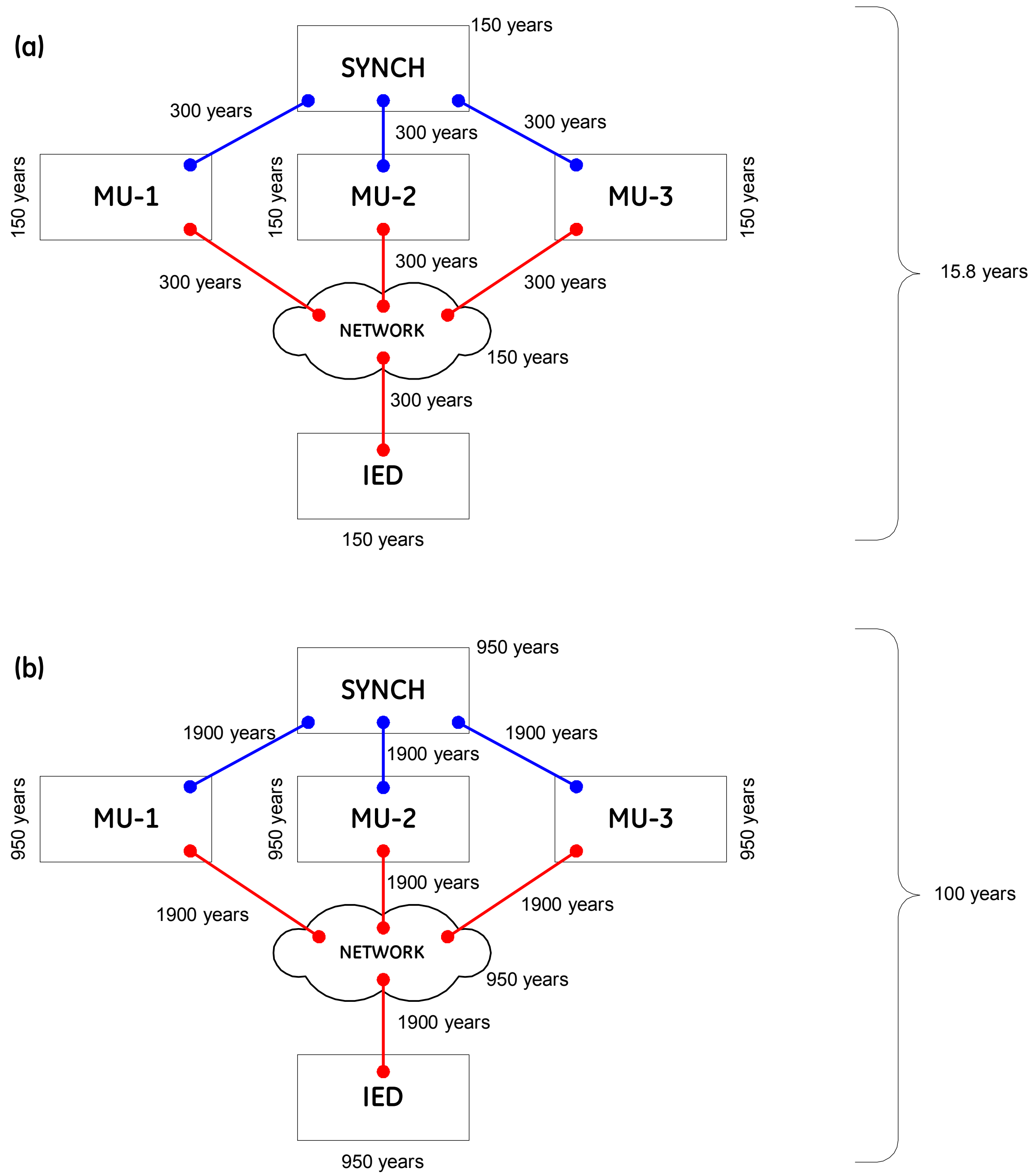


Fig. B-1.
A sample process bus based protection application with arbitrary MTTF values of components (a). Required MTTF levels leading to 100 years of MTTF for the system (b).

for its merging units. This eliminates 2 components from the system (synchronization clocks and their redundant connections) and increases the MTTF to 25 years.

Assume further variants as depicted in Figure B-3.

The system of Figure B-3a eliminates the explicit network, and connects the IED with its merging units. The removes several components from the system, and increases its MTTF to 30 years.

Figure B-3b probes the impact of redundant connections. If the redundant connections are removed, the system degrades to 27.3 years of MTTF.

Figure B-3c assumes redundant merging units and redundant connections. Each merging unit and its connection has a MTTF of 100 years. This subassembly is duplicated in the architecture of Figure B-3c yielding 150 years of MTTF for the merging unit data. The system requires all 4 elements to work (IED and 3 redundant merging units), resulting in the overall MTTF of 37.5 years.

Assume the arbitrary relative MTTF data for the components of the system in Figure B-3c. In order to achieve 100 years of the system MTTF, the IED and merging units will have to be characterized with 400 years of MTTF, and the connections with 800 years between failures.

The above numbers are within the reach of today's technology. It is important to realize that today's IEDs are

Fig. B-2.
Alternative solutions using simplification or added redundancy.

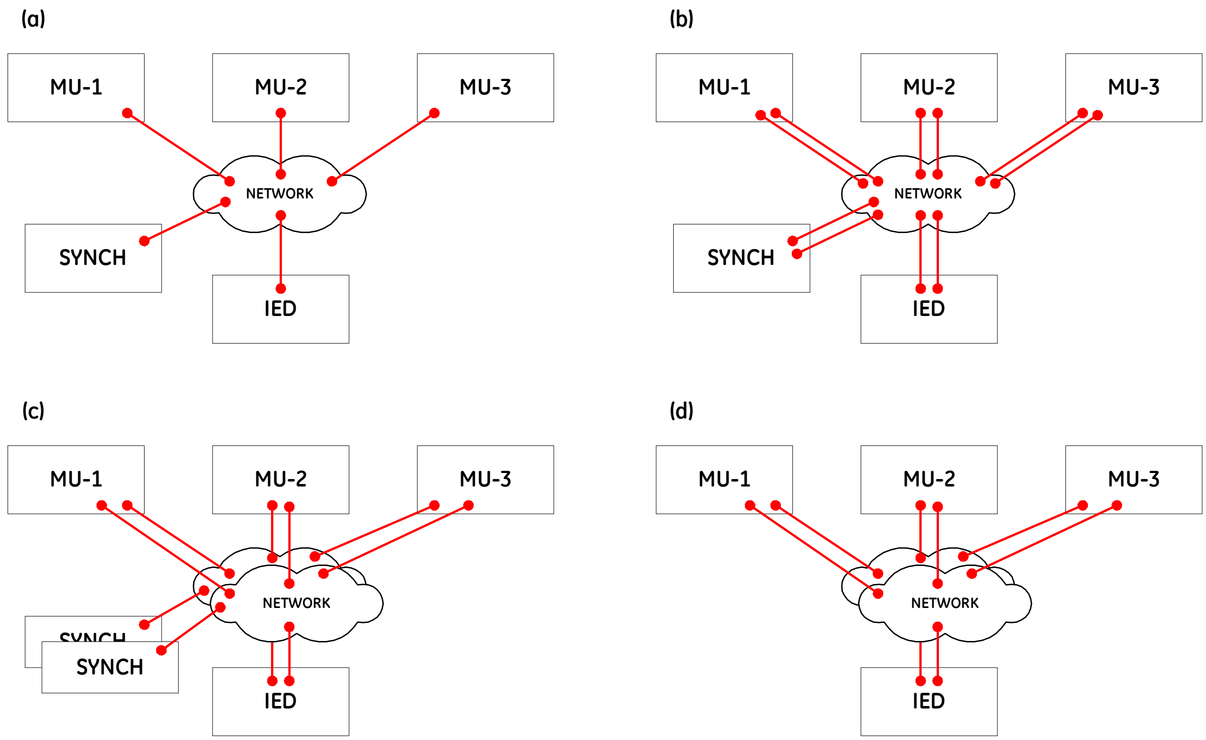
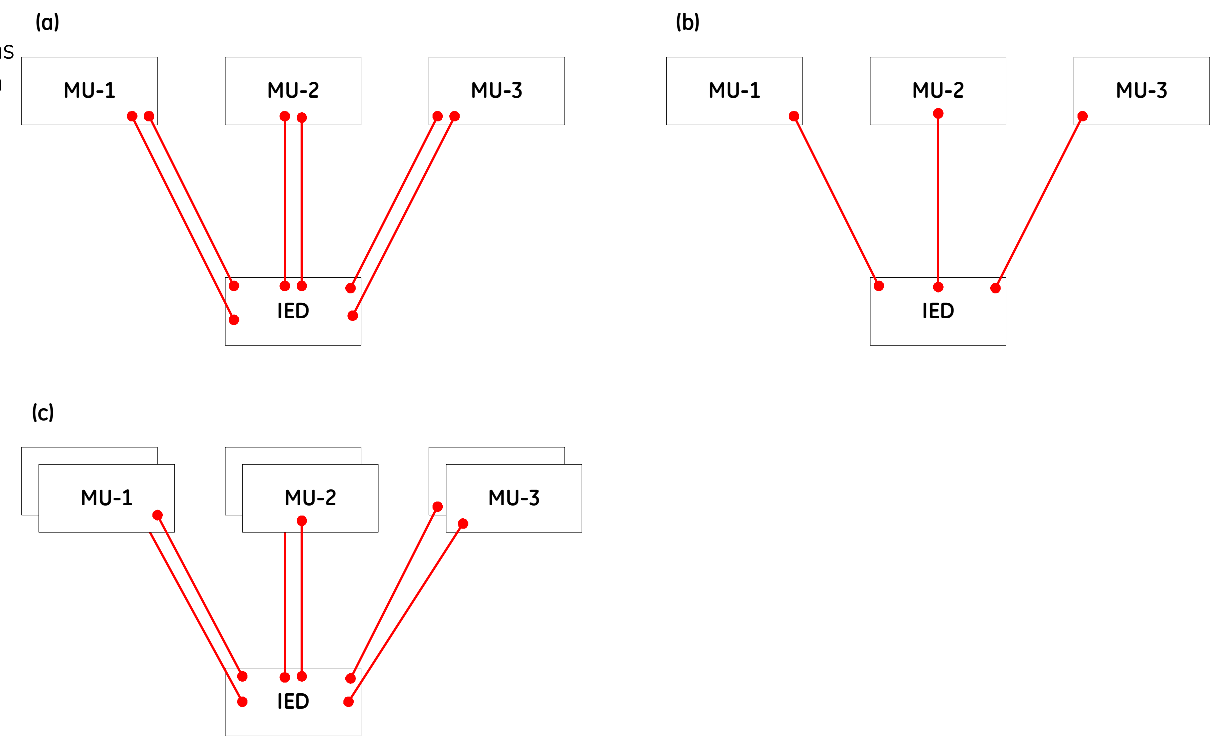


Fig. B-3.
Alternative solutions using simplification or added redundancy.



built as subsystems (see Figure B-4). These subsystems are CPU with communications, power supply, binary input modules, ac input modules, contact output modules, etc. For the system (IED as known today) to have a 100 years of MTTF, the subsystems must be much more reliable. Assuming equal reliability of the 5 major subsystems of the IED in Figure B-4, each subsystem has an MTTF of about 500 years.

Assume now those existing subsystems are relocated to compose a distributed protection system with I/Os moved to the switchyard (merging units), and input-less IED left in the control house. Assume the arbitrary reliability of 500 years for each subsystems is improved by the factor of 2. Assuming 500 years of MTTF for the direct connections, such system would reach the level of 71 years of MTTF as depicted in Figure B-5.

If the merging units and their connections are redundant, the system of Figure B-5 would reach exactly 100 years of MTTF.

This surprising number results from a simple fact: The system of Figure B-5 is very similar to today's IEDs. The complexity and part count are similar yielding approximately the same overall MTTF level. The added components (connections and power supply modules in the merging units) are compensated by redundancy of those elements, and assumed two-fold increase in reliability of the subsystems.

It is intuitively obvious that a process bus protection system set up with today's off-the-shelf components (complex merging units fed for non-conventional instrument transformers and explicitly synchronized via their IRIG-B inputs and communicating via Ethernet network) would have reliability numbers similar to the example of Figure B-1a. This is because of substantial increase in the total part count of the system as compared with today's microprocessor-based relays. A successful system for replacing copper wires with fiber optics would have to keep the total part count and complexity at the level of today's relays.

There are challenges in designing such a system primarily time synchronization, and sharing data from merging units to multiple IEDs without an explicit network, while keeping the total count of merging units at a reasonable level.

It is justified to assume relay vendors have / are working on solutions. It is quite obvious that the interoperability protocols of the IEC 61850 in the areas of process bus and peer-to-peer communication are of little help in solving this architectural/reliability puzzle.

Fig. B-4.
Today's IED as a system.

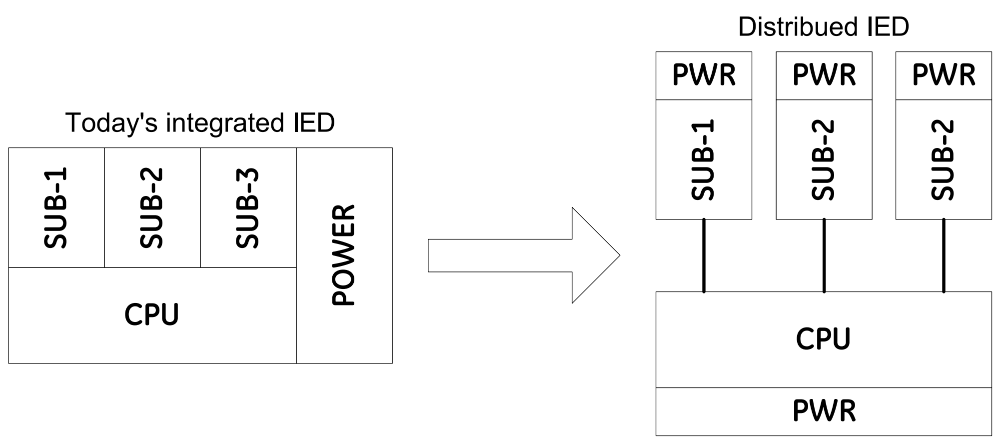
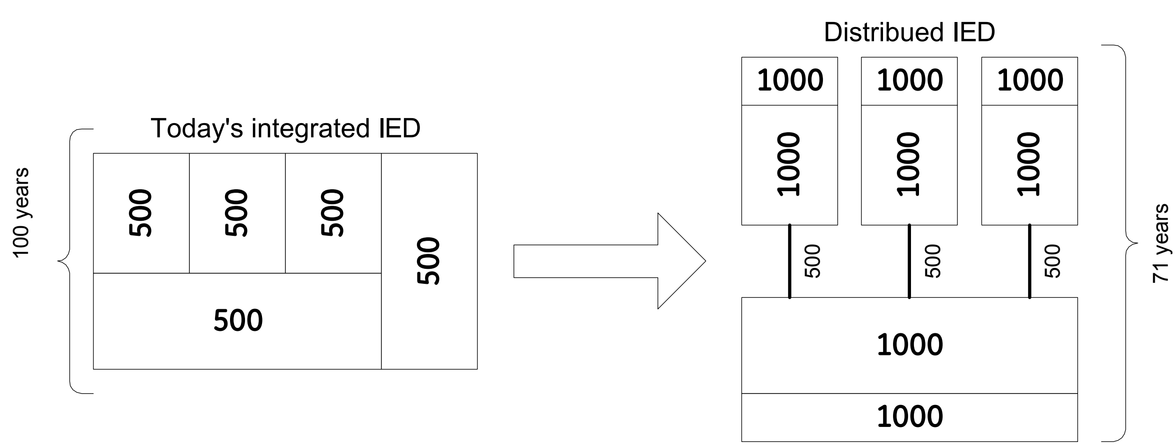


Fig. B-5.
Today's IED as a distributed system.



Monitoring Ageing CCVTs

Practical Solutions with Modern Relays to Avoid Catastrophic Failures

Bogdan Kasztenny, Ian Stevens

Abstract – Ageing **C**oupling **C**apacitor **V**oltage **T**ransformers (CCVTs) can pose safety problems and possibly restrain system operations. Catastrophic failure of a CCVT could start a widespread fault in the substation and/or endanger personnel working in a close proximity. The latter becomes a real danger when inspecting a suspicious CCVT or when Live Line work is being performed. CCVT monitoring becomes more and more important as the installed population of CCVTs ages with sporadic incidents of catastrophic failures alerting both field personnel and dispatching managers regarding safety and liability.

Microprocessor-based protection relays facilitate cost-efficient and broad deployment of CCVT monitoring functions across the organization.

First, modern relays allow programming a number of indicators that alone, or in combination, are reliable enough to raise alarms and initiate an in-depth engineering analysis.

Second, these relays can provide data recording and remote access. This data includes high-resolution data such as oscillography, and long-term trending such as the magnitude profiling.

Third, relay-based CCVT monitoring schemes can be retrofitted in the existing installations. In many cases with a simple wiring and setting changes, existing relays could provide a solid CCVT health indication.

The combination of reliable alarming via protective relays with remote access yields a cost-efficient, easy to implement, and safe to operate, solution.

This paper presents a number of CCVT health indicators that could be programmed on modern relays via logic and simple math operands in order to monitor the CCVTs with a minimum material and labor investment.

1. Introduction

CCVTs are widely used in transmission and distribution substations to provide proportional, secondary single-, or three-phase voltages for protection, metering and control functions. The CCVT has three basic components: a capacitor divider made from a group of high voltage capacitors and a lower voltage grounding capacitor(s), and a voltage transformer/filter element which provides the single phase secondary voltage (Figure 1).

One common problem in electricity supply is the ageing population of CCVTs (Figure 2). Over many decades, the CCVT components will degrade and/or experience overvoltages. This may result in capacitor element failure and the secondary voltage progressively losing its integrity, but more importantly, the CCVT can explode if sufficient number of capacitor elements fail. The explosion can rupture the porcelain shell and radiate porcelain fragments and hot synthetic oil within the local area (Figure 3). This debris is a real threat to staff safety and to surrounding plant (in a similar incident in a capacitor bank, Powerlink Queensland suffered damage to 26 plant items from a capacitor can explosion). In addition, the CCVT is commonly located on the substation bus and bus protection will clear the fault. This can result in loss of supply to a large number of customers and possibly incur a penalty from the Energy Regulator. Where CCVT supplies degrading voltages to revenue metering, the billing data will contain an error. The billing discrepancy can be substantial if the magnitude or phase error is small enough to remain undetected for very long periods of time, but large enough to accumulate into a significant energy measurement error.

Powerlink is replacing its line protection relays with microprocessor-based protection relays and it is beneficial and cost effective to provide VT monitoring within this relay.

Emerging considerations in Australia are the legal requirement for managers to exercise Duty of Care, especially with respect to staff safety [2]. This consideration requires managers to ensure staff safety in the substation and approved procedures exist for staff to safely isolate faulty HV assets.

This paper provides methods of monitoring with microprocessor-based protection relays and providing information for safely isolating CCVT assets, in a timely manner and thus maintaining security of supply. In addition, novel methods of monitoring a single phase CCVT are presented.

2. Failure Modes and Consequences

The failure modes for conventional CCVTs are:

- Failure of one or more capacitor elements in the HV stack (C1), which is usually oil impregnated. The critical factor is the increase in voltage and stress upon healthy capacitors as each capacitor fails, e.g. 275kV CCVT has about 160 capacitors in C1. This can lead to an avalanche failure mode and a possible explosion.
- Failure of one or more capacitor elements in the LV grounding stack (C2), which is usually oil impregnated. The important factor is the decrease in secondary voltage. However, this failure mode can result in an explosion as experienced in New Zealand when C2 failed due to a faulty connection.
- Failure of the intermediate voltage transformer or the series reactor, which can result in changes in phase angle and/or voltage.
- Failure of the ferroresonance suppression circuit, which can produce waveform distortion, changes in phase angle and/or voltage. It is possible for ferroresonance events to occur if the connected burden has too low a knee point voltage in

its transformer(s). Powerlink experienced an intermittent connection in the CCVT's ferroresonance damping circuit and this fault produced a reasonably stable voltage (64V compared to 67V on healthy phases) and fluctuating frequency in one phase between 47 to 53 Hz (50Hz nominal; measured with DMM) in the output voltage. Investigation revealed there was an open circuited choke in the ferroresonance damping circuit in the CCVT basebox due to an imperfectly soldered joint in the wire, within a sleeve in the choke toroid. This open circuit had the effect of directly shunting portion of the VT primary winding

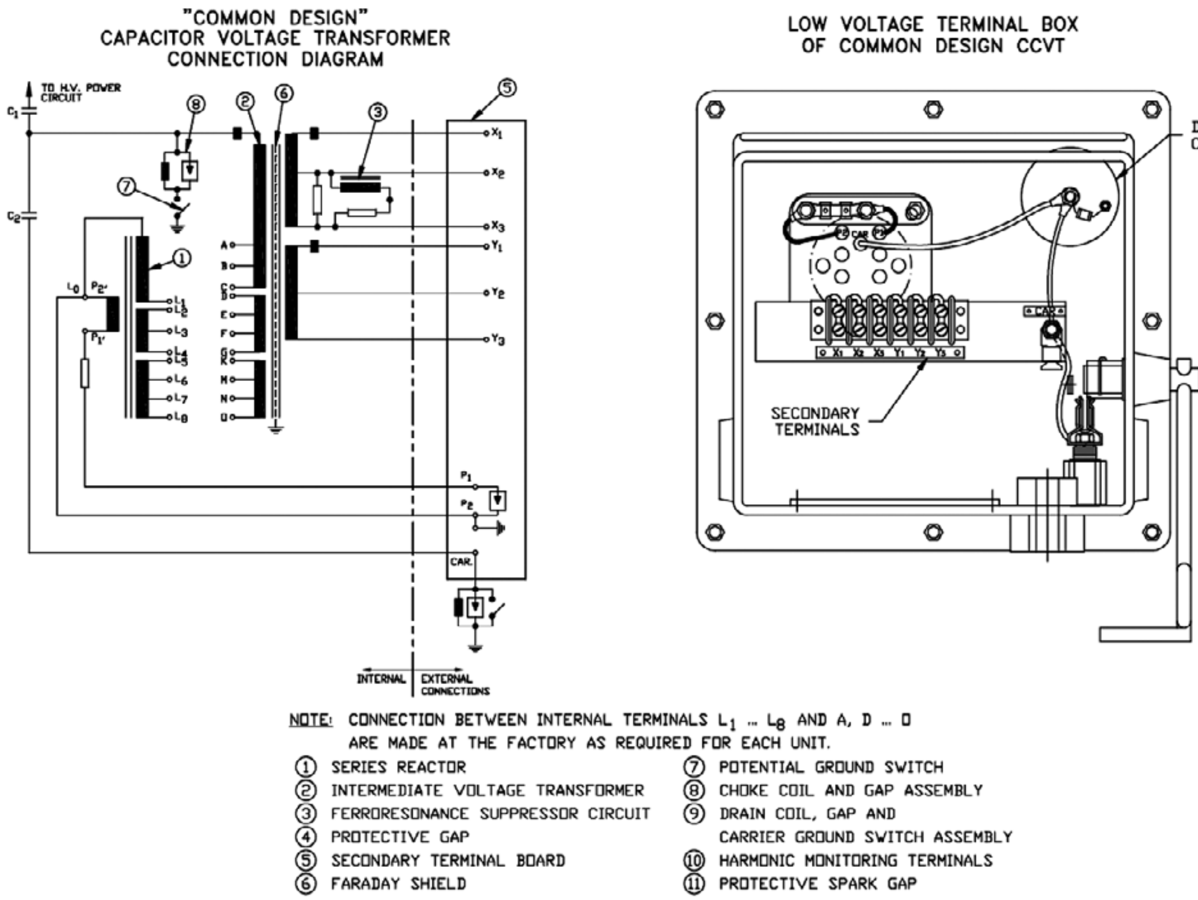


Fig. 1.
Construction of a typical CCVT [1].

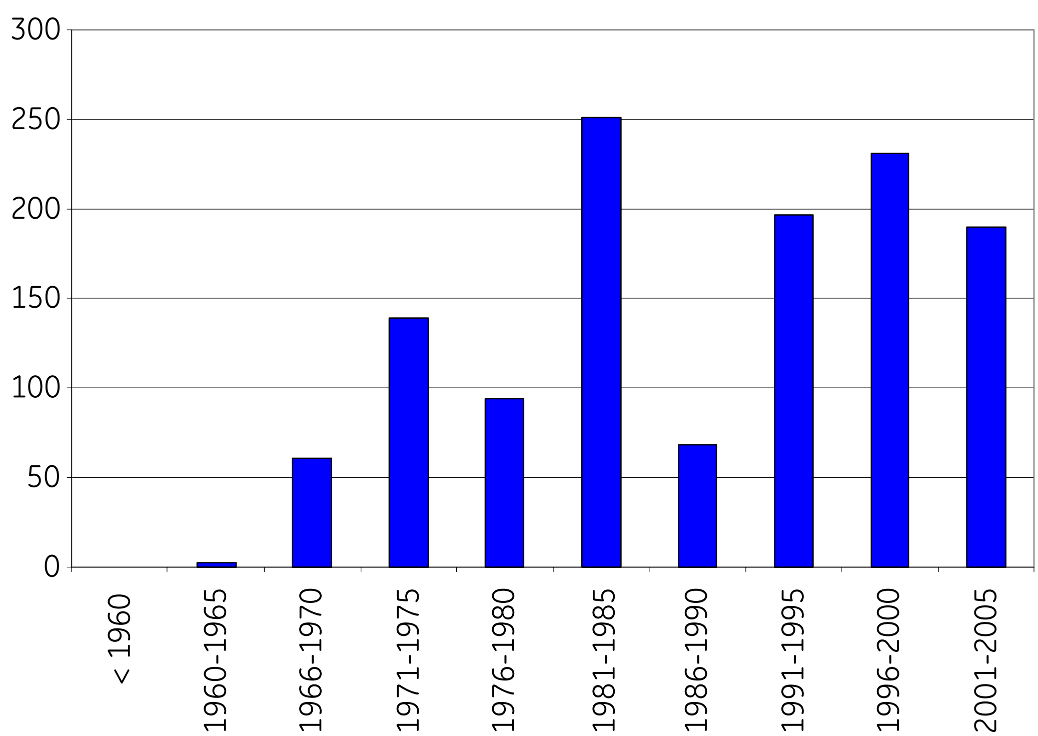


Fig. 2.
Distribution of CCVTs purchased by Powerlink (sample plant, all still in service).

with a capacitive impedance rather than the normal high 50Hz impedance and would have affected the voltage output.

• Failure of the filter circuit or spark gaps, which are used to minimize harmonic and transient voltages in the output voltage. Frequent overvoltage events can wear out the spark gap and the flashover voltage level increases. This will increase the stress on components in the VT circuit and these eventually fail.

• External flashover along the porcelain bushing due to pollution contamination of flashover clearance. The cause is incorrect CCVT specification for the local environment when purchasing the CCVT.

• Failure of expansion membrane, which results in contamination of oil and capacitor failure. Powerlink has experienced failure of the expansion membrane in a magnetic VT because the membrane was incompatible with the synthetic oil. This eventually resulted in the VT exploding.

Fig. 3.
Porcelain debris after rupture of a VT.

• Failure in gasket seal which may allow high moisture content (>30 ppm) in oil which reduces the withstand voltage capability and increases stress in basebox items which use oil impregnated paper.

• Low oil condition due to prolonged oil leak which results in capacitor failure.

The capacitor, series reactor and intermediate voltage transformer components can be degraded by high harmonic currents (e.g. AC-powered trains), lightning or prolonged ferroresonance conditions.

The consequences of CCVT failure could be:

• The CCVT can explode if sufficient number of capacitor elements fail and arcing occurs within it. The explosion can rupture the porcelain shell and radiate porcelain fragments and hot synthetic oil within the local area. This debris is a real threat to safety of staff and to surrounding plant.

• The CCVT is commonly located on the substation bus and bus protection will clear the fault. This can result in loss of supply to a large number of customers, or weakened system integrity (stability problems).

• The failure mechanism was due to a generic or age related fault. Thus the remaining CCVTs could be deemed suspect and, without monitoring, result in constraints upon system operations and substation work.

• Progressive failure over a long period of time will cause incorrect revenue billing because one secondary voltage was incorrect. Microprocessor revenue meters will alarm if the voltage exceeds the typical limits of 80% to 115%. CCVT monitoring can overcome this problem, eliminate the need to repay/recoup the amount of incorrect billing and maintain a company's reputation.

3. Present Monitoring Schemes

The present monitoring schemes are limited to three-phase groups of CCVTs. The commonly used methods are based on under/over voltage protection relays, which create an operational window and alarm for voltages outside the window (except for near zero voltage where the CCVT was de-energised). This method is an absolute measurement and is relatively insensitive because the window thresholds must be set above possible network voltage fluctuations (±10% of nominal). Therefore, the alarm could be raised just before the CCVT could explode.

A novel method developed by TransGrid (an Australian transmission authority) was to monitor the half wave rectified, three-phase voltages with a missing pulse detector [3]. A high voltage will cause its rectified phase pulse to dominate, thereby causing one healthy pulse to be missed (Figure 6). A low voltage will cause its rectifying diode to be biased off, thereby causing the phase pulse to be missed. The missing pulse detector fed into a time delay and output relay circuits. This method is sensitive to voltage but relatively insensitive to phase drift as detection occurs around ±60°. This method is a relative three-phase method, and it has been successful. However, it requires a separate relay for each three-phase CCVT and it cannot provide additional information as to which phase failed.

These monitors were set with a 10 minute time delay so that any transient voltage fluctuations from the electricity network or secondary system loads is filtered out. The time delay prevents incorrect and unnecessary alarms, which can give CCVT monitoring a bad reputation with resulting distrust and poor response to legitimate alarms.

Dissolved gas analysis of oil samples taken from CCVTs will provide static assessment on the health of each CCVT. The

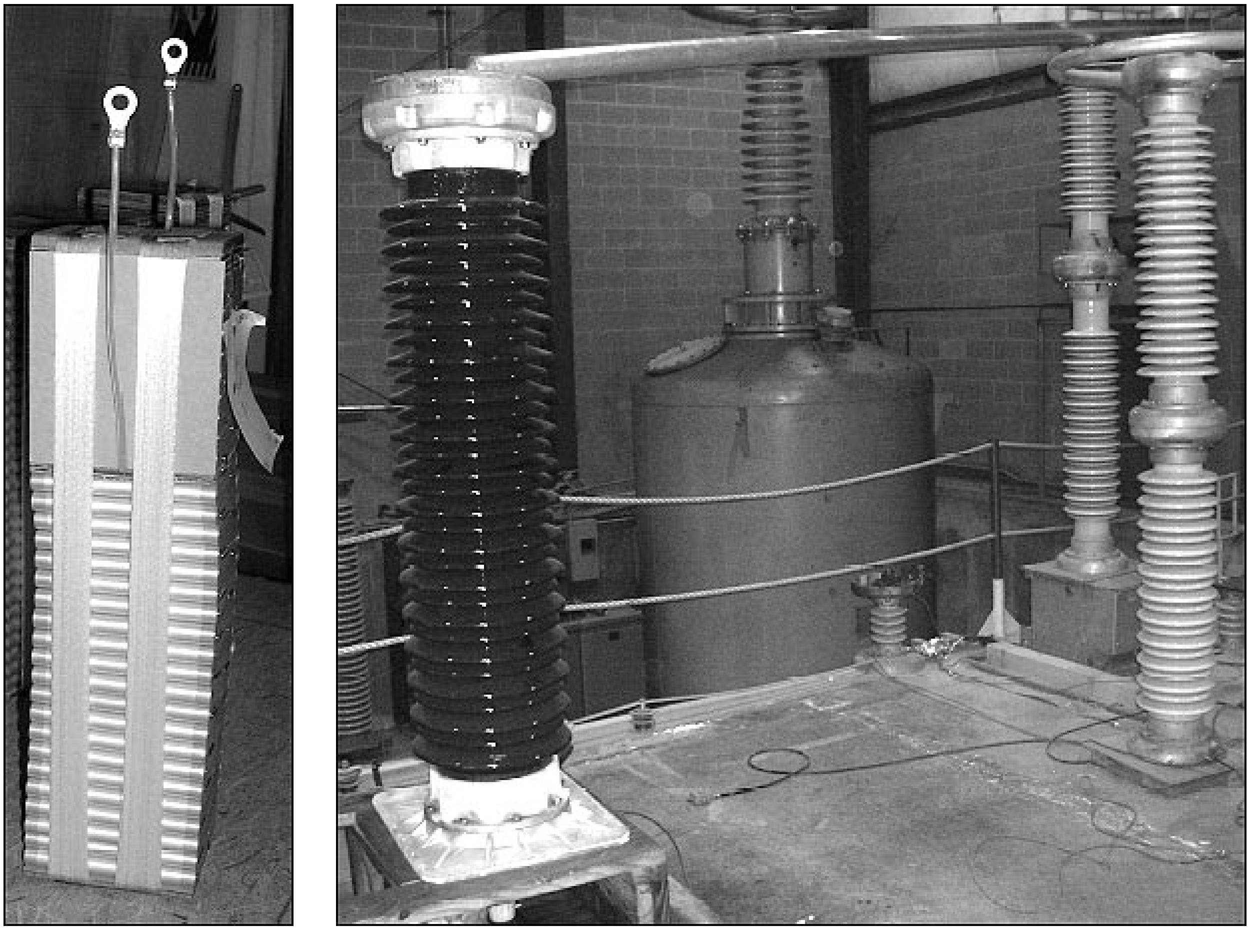


Fig. 4.
New CCVT capacitor stack (left) and CCVT under high-voltage testing (right).

disadvantages are high cost and labour requirements, and it's possible the CCVT could fail between oil samples.

4. Attributes for CCVT Monitoring

The required attributes for CCVT monitoring are:

- Continuous, reliable monitoring is provided and the alarms are supervised.
- It uses a relative voltage measurement technique so as to give sensitive monitoring irrespective of unrelated transient voltages. Microprocessor-based protection relays measure zero sequence and/or negative sequence voltages providing for this attribute.
- It logs the voltages in a FIFO record of suitable length and frequency for post fault analysis.
- It filters out transient sequence events such as secondary transient loads on one phase, network faults or switching of reactive assets such as shunt capacitor banks and reactors. Typically, a long time delay is used but this can still produce fleeting alarms that may be ignored by the operator.
- The installed and maintained costs for providing monitoring are low as the frequency of CCVT faults is very low but the consequences of a fault are very high and costly. The cheapest monitoring available is to incorporate it into existing feeder protection or SCADA control equipment. This equipment already has three-phase voltages connected, and may provide a SCADA communication link (such as DNP 3.0) to annunciate CCVT alarms.
- The provision of voltage waveforms in real time or as records allows staff to investigate the problem and take appropriate actions to maintain staff safety and security of supply.
- The above information is provided by remote interrogation and in a timely manner. Powerlink has developed a 2MB Wide Area Network (WAN), which connects to the majority of substations and it enables remote interrogation within 5 minutes.

Modern microprocessor-based protection relays provide many of these attributes and are ideal for performing this monitoring.

5. System Conditions and Voltage Monitoring

Operating range of electricity network is typically ±10% of the nominal voltage. However under system abnormal conditions (e.g. one feeder out for maintenance and an associated supply feeder trips), it may be possible for three phase voltage dips or brown out events to occur. It is important that resultant, incorrect CCVT monitoring alarms do not occur and increase the workload of network control centre operators during this crisis.

The electricity network is designed to limit the levels of the negative-sequence voltage to a maximum 2% averaged over

Fig. 5. Examples of failed CCVT capacitor stacks.

a 1-minute period. The quiescent level is typically around 0.5%. This limit was derived from the adverse impacts upon motors producing torque in the opposite direction and overheating their rotors if exposed to negative-sequence. For example, NEMA recommends keeping the continuous negative-sequence unbalance to within 1% [4]. Therefore, these levels will give guidance for selecting the pick up value and minimum operating time for CCVT monitoring. Some extra high voltage networks are operated untransposed with significant negative-sequence in currents and voltages. If this is the case, zero-sequence voltage could be considered instead.

Any measurement grade VT is designed for operation under any burden conditions such that magnitude and phase errors are less than accuracy class, which usually have limits of 1.5% and 1°. However, VT burdens are generally balanced so there will be minimal magnitude and phase differences between phases, i.e. all magnitude and phase errors will have the same sign.

Therefore under healthy CCVT conditions and with no negative sequence voltage in the electricity network, there will be negligible negative-sequence voltage.

The major consideration in the electricity network is power system faults which are limited to around 10s duration. Therefore, the negative-sequence time guideline will supersede this requirement.

6. Proposed Voltage Monitoring Schemes

6.1. Methods for three-phase sets of CCVTs

The advent of microprocessor-based protection relays can give the opportunity to provide CCVT monitoring at virtually no additional cost. The commonly used transmission feeder protection systems are distance protection and/or current differential protection, which may have distance back up protection. The distance protection function requires three-phase voltages and hence it is ideal to perform CCVT monitoring. The new method can be applied on these relays utilizing their metering, logic and math capabilities.

One design objective was to eliminate the need to wire the CB status into the monitoring system. Therefore, overvoltage elements are set low (15-20% of nominal) to indicate the VT is energised. Note if the capacitively coupled voltage on a de-energised bus or feeder is high, it may be necessary to increase the supervising setting.

6.1.1 Monitoring with Negative-Sequence Voltage

Negative-sequence voltage is a preferred monitoring method because it provides relative coverage over the whole voltage phasor range, and negative-sequence overvoltage elements are often available in microprocessor-based protection relays for purposes such as weak-infeed logic.

Assume phase A is failing while phases B and C display virtually no errors. The negative-sequence derived from such voltages is:

$$V_2 = \frac{1}{3}\left(V_{A(\text{sec})} + a^2 \cdot V_{B(prim)} + a \cdot V_{C(prim)}\right) \qquad (1)$$

which can be re-written as:

$$V_{A(\text{sec})} = 3 \cdot V_2 - \left(a^2 \cdot V_{B(prim)} + a \cdot V_{C(prim)}\right) \qquad 2)$$

Expression in the brackets is minus the primary ratio voltage in phase A, and therefore:

$$V_{A(\text{sec})} = 3 \cdot V_2 + V_{A(prim)} \qquad (3)$$

Equation (3) means that assuming balanced primary voltages, and phase A voltage failing, the negative-sequence overvoltage function defines a limit around the true ratio voltage in the shape of a circle with the radius of three times the applied pickup (Figure 7).

This provides for good sensitivity to angle shifts in the monitored voltage. Assuming the V_A magnitude does not change and the failure shifts the vector, the following shift will trigger the negative-sequence function if set to pickup at V_2.

$$\alpha = 2 \cdot \arcsin\left(\frac{3}{2} \cdot \frac{V_2}{V_A}\right) \approx 2 \cdot \arcsin\left(\frac{3}{2} \cdot V_{2(PU)}\right) \qquad (4)$$

And furthermore:

$$\alpha_{(\text{deg})} \approx \frac{3 \cdot 180}{\pi} \cdot V_{2(PU)} \qquad (5)$$

For example, if set to 0.03pu, the negative-sequence overvoltage function would trigger when the secondary voltage shifts by about 5.2 degrees. This is the

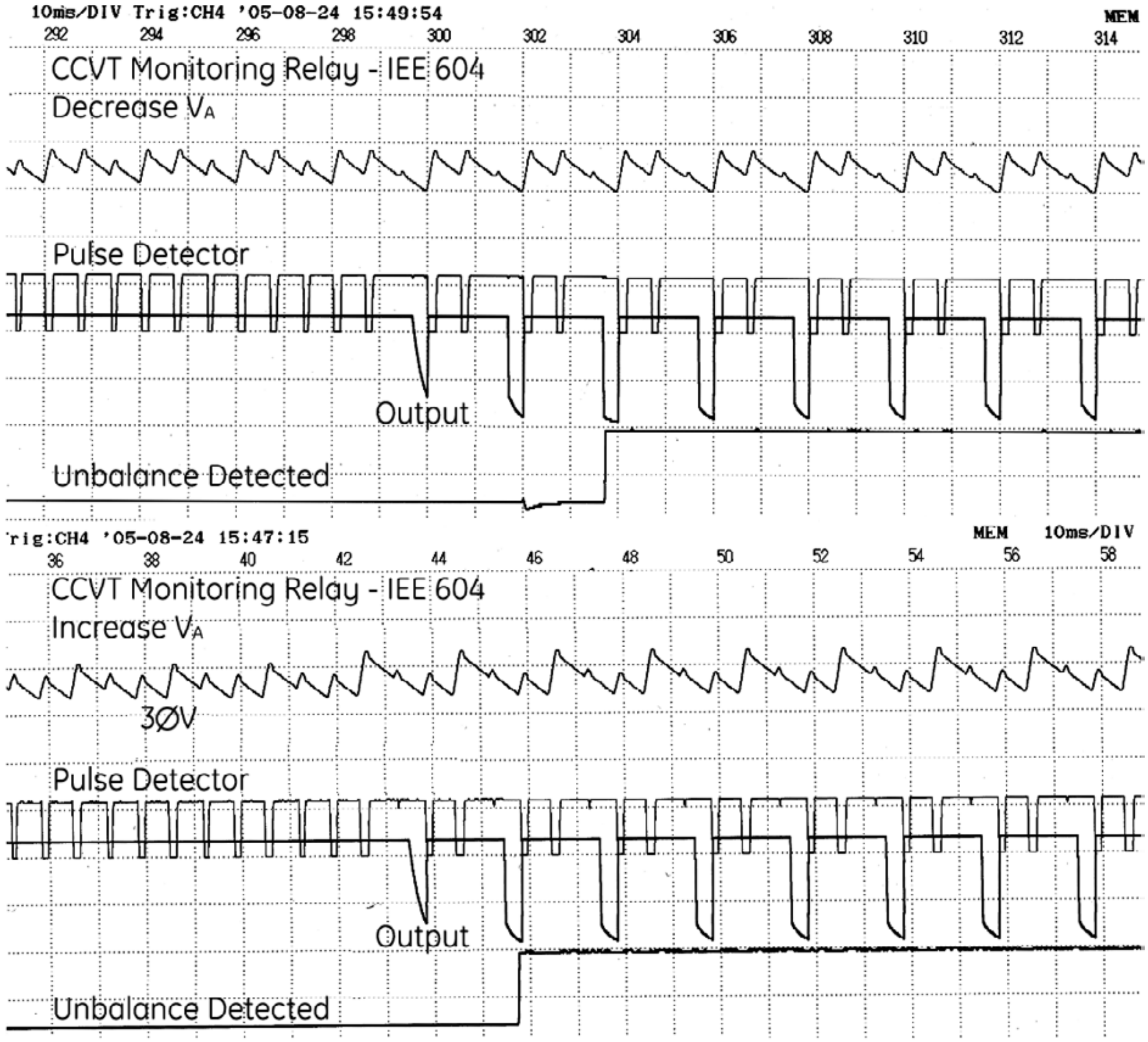


Fig. 6.
Illustration of the CCVT monitor [3].

worst case scenario; if the magnitude changes, either increases or decreases, even smaller angle differences will trigger the negative-sequence function (see Figure 7).

However, sensitivity to magnitude changes is lower. Assume no angle error occurs as a result of the failing CCVT. It will take a magnitude excursion of 3 times the negative-sequence pickup to trigger an alarm. For example, with a 0.03pu pickup, it will take a change in magnitude by 9% to trigger the alarm. This may be considered not sensitive enough.

The high voltage capacitor stack (C1) may be composed of one hundred cans at 132kV level, 160 cans at 275kV level, etc. Approximately, the voltage ratio changes in proportion to the amount of shorted capacitor cans. For example, at 275kV level with 160 cans, it will take 2 cans to cause a change of 1.2% in the voltage; a single can failure would cause a 0.6% change, which could be below the class error of the transformer. This sets a limit on the minimum number of shorted cans that could be detected. Failures of the low voltage stack have a more dramatic effect on the ratio and could be detected much easier.

Sensitivity to magnitude excursions can be improved by monitoring differences between the magnitude of the A phase voltage and reference phases B and C, as shown in Figure 8.

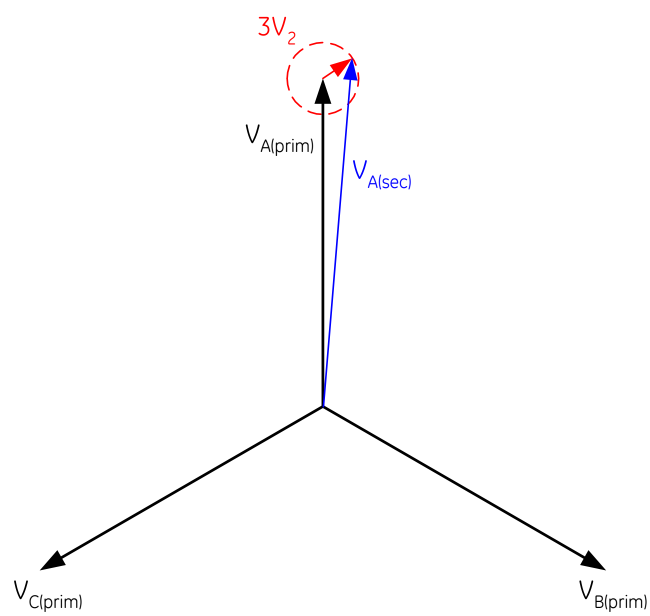


Fig.7.
Operating region of the negative-sequence overvoltage assuming B and C voltages normal.

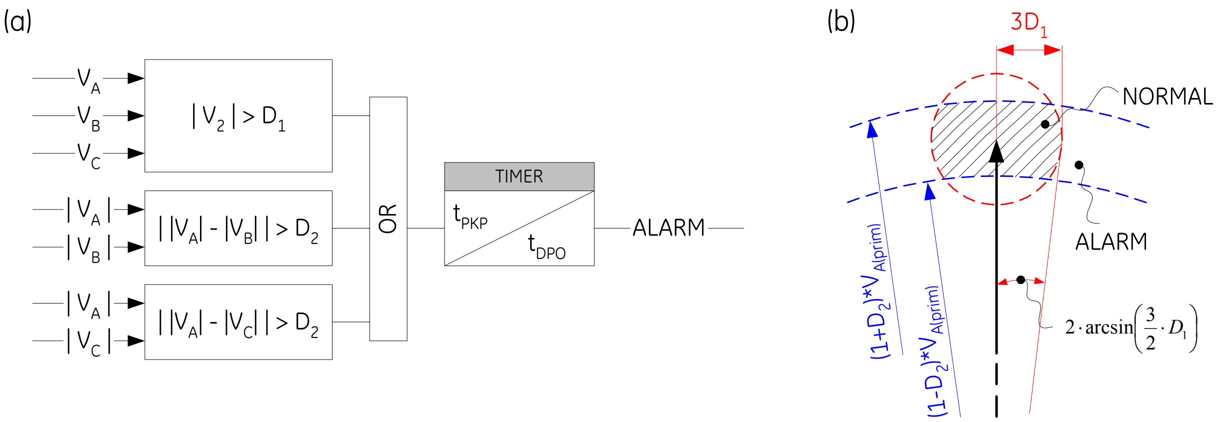


Fig. 8.
Negative-sequence overvoltage monitoring logic (a) and effective operating characteristic (b). All expressions are per unit.

A delay timer is applied to ride through faults, single-pole tripping and reclosing sequences and other switching events. Applying scheme of Figure 8a, a normal/alarm operating region is shaped as shown in Figure 8b.

Typical settings are negative-sequence overvoltage pickup of 0.03pu (D_1 threshold), magnitude differential pickup of 0.06pu (D_2 threshold), 120sec time delay (t_{PKP} delay), and 10 minute dropout time (t_{DPO} delay). The 10 minute duration ensures this problem is not considered a fleeting event.

A practical implementation may require connecting two timers in series: the first timer is a zero pickup, and small dropout timer. This timer is meant to prevent reset of the main timer during sporadic situations when the negative sequence voltage drops temporarily to low values, e.g. varying frequency output from intermittent connection in CCVT ferroresonance circuit. The second timer is the main, 120 sec pickup, 10 minute dropout timer.

6.1.2 Using change over time to increase sensitivity

Method of section 6.1.1 uses a steady state approach: it detects abnormal situation after it occurs and continues to be steady state. For example, when a can fails short in the HV stack of the divider, the magnitude of the secondary voltage increases and is driven by a permanently higher ratio. A failure in the tuning reactor can lead to a permanent phase shift in the secondary voltage. Because of the relatively long time delay, the method requires the failure to "stabilize" before it could detect it. At the same time the lowest possible pickup level must be above the normal steady-state difference between the phases.

In order to make the detection more sensitive, a change over time for the differential magnitudes could be applied as shown in Figure 9.

First, the difference between the two voltage magnitudes is derived. This difference may be as high a 2-3% under normal conditions, requiring the threshold in the previous method to be well above that level.

Second, the change over time is measured by comparing the present value of the difference with its historical, T sec old value. If a change greater than D_3 occurs, the output of the comparator is asserted. The value of T is set to 200-300 seconds. The threshold could be set as low as 0.02pu. Here, the steady state errors in the CCVTs and the relay are filtered out by using the change over time. Also, the natural fluctuations in each individual voltage are filtered out by using the differential magnitude voltage.

Third, the output of the "differential over time" comparator is connected to a timer (set at 120 sec).

Figure 10 illustrates this principle by showing the A and B voltage magnitudes (a), the magnitude differential (b), change over time of the differential, and the operating flag (c).

This method will generate a single alarm and it will reset afterwards. This must be taken into account when programming post-filtering of alarms generated by this version of the logic.

Methods of Figures 8 and 9 shall be used together to produce permanent alarm on substantial voltage deviations (Fig.8), and single alarm on small voltage deviations (Fig.9).

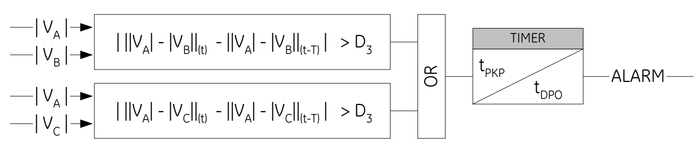


Fig. 9.
Monitoring logic responding to fluctuations of the differential magnitude.

6.2. Methods for single CCVTs

Presently single phase CCVTs are not monitored at Powerlink because of the difficulty in obtaining a reliable reference quantity.

6.2.1 Monitoring with Negative-Sequence Voltage via Pseudo Three-phase Arrangement

The three-phase steady state method of section 6.1.1 can be used for this purpose assuming one could "borrow" the two other phases from CCVTs that are measuring the same primary voltage. Quite often this is possible. A single CCVT on the bus facilitating synchrocheck against a three-phase full set of line CCVTs is a typical case.

With reference to Figure 11, extra security conditions are checked. First, using overvoltage functions one needs to make sure the monitored (V_X) and the reference (V_B and V_C) CCVTs are energized. Second, one needs to monitor the position of breakers/disconnectors to make sure the monitored and reference CCVTs are connected to the same metallically coupled portion of the bus (i.e. the reference voltages are truly valid references). Also, if the reference CCVT is monitored, its health indicator could be used to supervise the logic.

Method of section 6.1.2 with increased sensitivity could also be used when "borrowing" other phase voltages.

6.2.2 Using reference from the same phase

This is a simple method that is based on using the reference voltage from the same phase. This could be done for a single CCVT, or for a set of three CCVTs with three pairs of voltages compared.

The comparison itself could be done using flexibility of modern relays as shown in Figure 12, or utilizing a synchrocheck function as illustrated in Figure 13.

Modern relays provide for a synchronism check function. This function can be used to monitor consistency of any two secondary voltages assuming the two CCVTs work with the same primary voltage. The three basic synchrocheck settings are selected as follows:

- Magnitude difference (D_7 threshold): 2.5-3 times the sum of CCVT worst-case error and relay worst-case error. This is driven by the assumption that one voltage is measured with the maximum in class negative error, while the other is measured with the maximum positive error. Therefore, the worst-case normal difference is twice the summated error of the CCVT and the relay. Assuming 1% CCVT error and 0.25% of relay error, the difference shall be set above 2.5% (4-5%).
- Angle difference (D_6 threshold): similar reasoning applies (twice the error of the CCVT and the relay). A 2-3^0 setting shall be sufficient.

Fig. 10.
Illustration of the method of Figure 9.

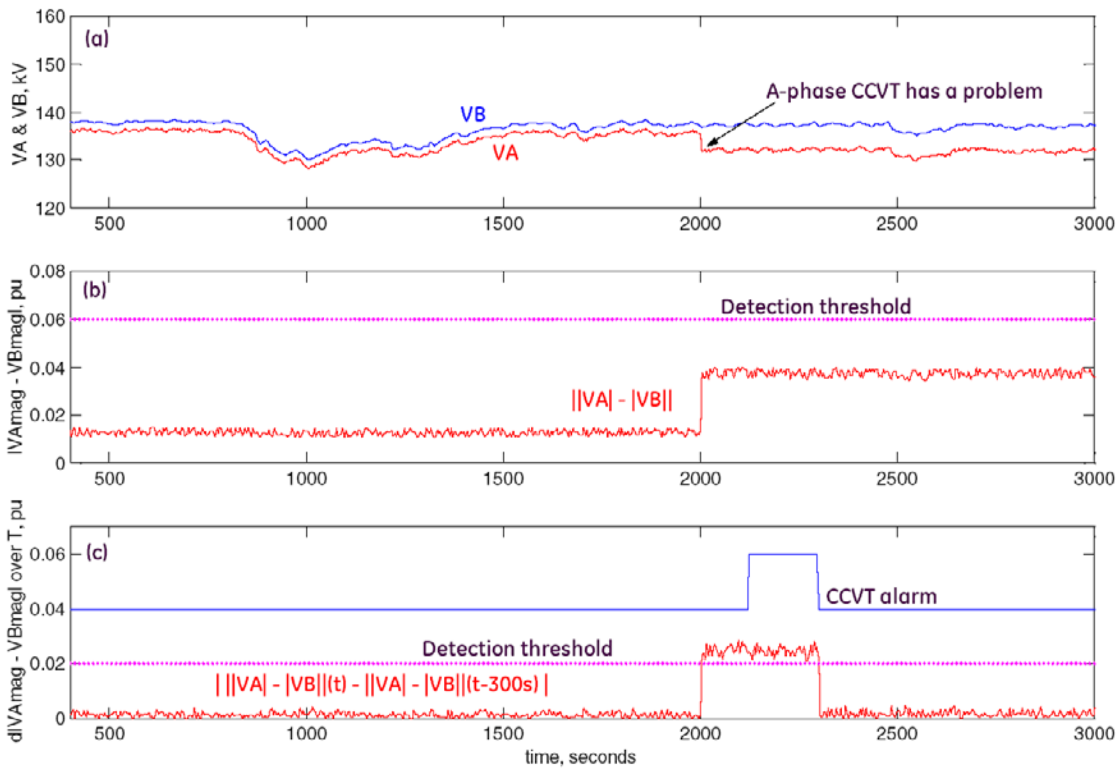
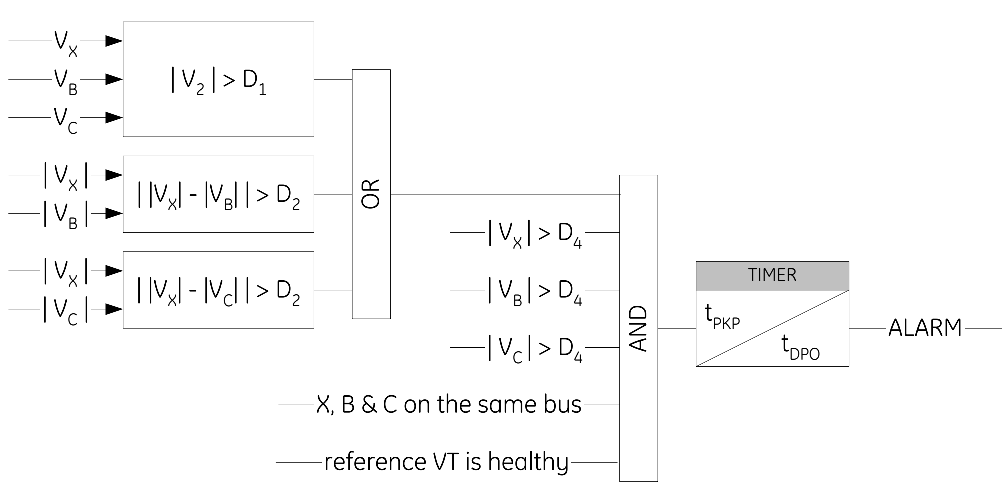


Fig. 11.
Monitoring single CCVT (VX = A phase) with negative-sequence while using reference voltages (VB & VC). All expressions are per unit.



• Frequency difference (D_5 threshold): 2.5-3 times the worst-case relay frequency measurement error. For example with a 10mHz worst-case measuring error, one could set the allowable delta-frequency setting to 30-50mHz.

Normally, all three parameters (magnitudes, angles, and frequency) are identical. Should any of them divert due to CCVT failure, the synchrocheck permissive flag resets. This opens the AND-gate, starts the timer, and sends an alarm if the situation persists.

Quite often the synchrocheck function is available as a standard feature, but is not used on a given IED. This gives an opportunity to use it as a voltage differential function to monitor a CCVT against a reference voltage.

In Figures 12 and 13 the supervision from the reference CCVT being healthy is optional. If the monitor triggers an alarm, the operators should understand that either of the two CCVT could have a problem, and both should be checked.

Method of section 6.1.2 with increased sensitivity could also be used when "borrowing" the same phase CCVT for reference.

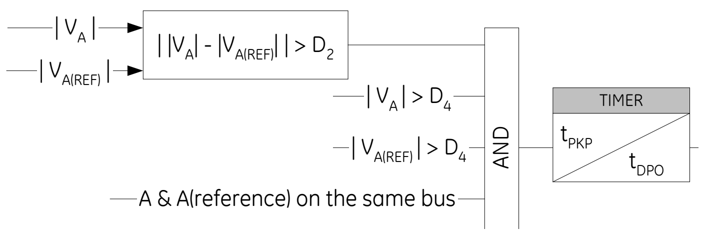


Fig. 12.
Monitoring single CCVT (A phase) by comparison with the same phase of a different CCVT.

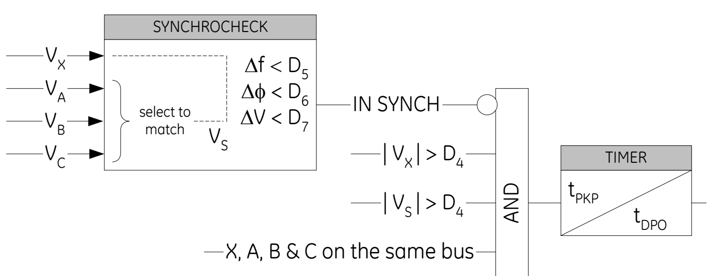


Fig. 13.
Monitoring single CCVT by comparison with the same phase of a different CCVT (application of the synchrocheck function).

6.2.3 Providing alternate reference VT

These monitoring schemes rely upon a reference VT, and it may be required to provide monitoring when the reference VT is de-energized. This is easily achieved by:

• A simple armature relay to appropriately select another reference VT;

• Within the relay, creating a monitoring scheme for each reference VT and ORing the outputs. (The above monitoring methods will not provide an output when the reference VT is de-energized.)

6.3. Additional Filtering of Alarms

The CCVT monitoring alarm outputs are sent in real time to the network control centre over SCADA for operator investigation.

Powerlink has decided to perform post processing by computer of all alarms received at the control centre. The aims are to detect high frequency of plant operation (e.g. tap changer operation of transformer) and to detect fleeting alarms, which may not be detected by humans.

CCVT monitoring alarms fall into the second aim and this is simple to achieve if a standard alarm naming convention is used. This computer filtering provides a safety net in the monitoring scheme.

Table 1 shows an extracted alarm record of a failing CCVT at a control centre.

6.4. Additional Features of Microprocessor-based Relays

Microprocessor-based protection relays provide additional functions beneficial for CCVT monitoring. Importantly, these relays provide oscillographic and event recording and data logging of voltages; all these can be remotely accessed over a communication link by the control centre operator (Figure 14). This enables quick, safe interrogation of possible CCVT failure and prompt removal of plant before a possible explosion and resultant supply interruption. This information is very useful for CCVT repair and detecting generic faults due to CCVT age or design related faults.

These additional features are extremely useful and cost effective to Powerlink.

7. Implementation on Modern Relays

Modern microprocessor-based protection relays provide for simple math capabilities. The CCVT monitoring function is not time critical, therefore a generic PLC-like math operations could be used for this purpose.

One particular solution uses a universal comparator to perform comparison, or rate-of-change monitoring for analog signals.

With reference to Figure 15 the universal comparator could have up to two signals configured as inputs in a differential mode. These inputs are any signals measured by the relay and include phasor magnitudes and angles, true RMS value, active and reactive power, magnitudes and angle of symmetrical currents and voltages, frequency, power factor, etc. Either two signals are subtracted (Figure 16a), a single signal is used (Figure 16b), a single inverted signal is used (Figure 16c), or a sum of two signals is used by cascading two comparators (Figure 16d).

The comparator could be set to respond to "signed" or "absolute" value of the effective operating (differential) signal. The absolute value allows for symmetric response for positive and negative values; the signed value allows for monitoring both the value and its sign. For example, to alarm on low power

Table 1.
Sample of SCADA logs prompting operators to investigate.

DATE	ALARM DESCRIPTION	DURATION
1/10/2003 16:36:32	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:14:39
31/10/2003 1:59:20	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:12:49
31/10/2003 2:14:00	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:10:10
31/10/2003 10:42:05	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:15:41
31/10/2003 13:31:45	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:16:11
31/10/2003 19:24:11	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:11:30
31/10/2003 20:08:40	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:16:30
31/10/2003 20:41:20	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:18:20
31/10/2003 20:57:02	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:11:32
31/10/2003 21:40:50	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:10:30
31/10/2003 22:20:28	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:10:50
1/11/2003 9:17:23	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:15:19
1/11/2003 9:42:43	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:10:31
1/11/2003 11:18:13	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:11:42
1/11/2003 12:00:41	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:10:50
1/11/2003 17:45:30	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:12:52
1/11/2003 18:46:18	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:13:58
1/11/2003 21:02:18	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:11:21
1/11/2003 22:32:17	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:17:59
2/11/2003 1:21:56	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:11:30
2/11/2003 1:48:14	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:11:20
2/11/2003 10:19:10	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:12:10
2/11/2003 11:55:39	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:12:30
2/11/2003 22:23:33	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:11:28
3/11/2003 2:11:43	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:15:20
3/11/2003 4:25:51	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:15:31
3/11/2003 10:52:57	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:13:30
3/11/2003 11:36:58	R-9 H016-RLEA 110KV FDR CCVT VOLTAGE ABNORMAL->NORMAL	0:15:00
	Total	28
	Maximum Time=	0:25:41
	Minimum Time=	0:10:10
	Average Time =	0:13:38

Fig. 14.
Example of remote interrogation of a microprocessor-based protection relay.
The site is 1,800km (1,110 miles) away.

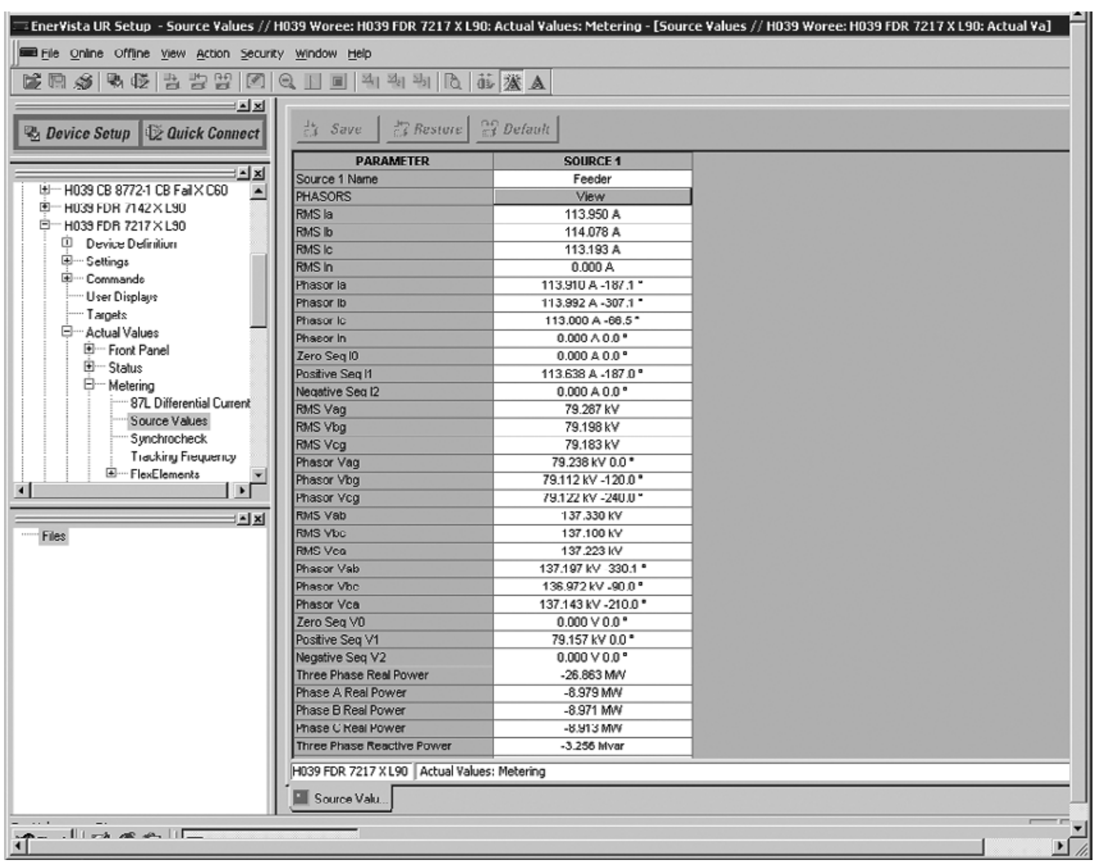
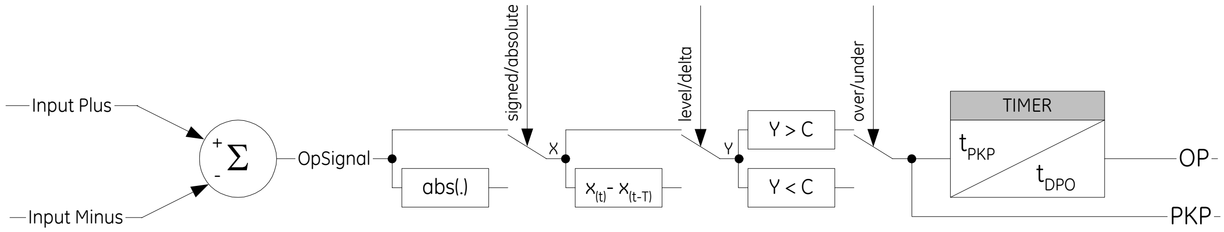


Fig. 15.
Operating logic of the universal comparator.



factor one would use
the "absolute" mode (Figure 17a). But to alarm separately on low leading, and low lagging power factor, one would use two comparators set in the "signed" mode (Figure 17b).

The comparator allows responding to either the value of the effective operating signal ("level" mode) or the change of the signal over a pre-defined period of time ("delta" mode). The former could be used to define functions such low power factor alarm, positive sequence undervoltage, negative-sequence overcurrent, over-frequency, under-frequency, etc. The later allows defining custom functions such rate-of-change-of-frequency, rate-of-change-of-power, etc.

Finally, the comparator could be set to perform "over" or "under" comparison against a constant user-selectable threshold. The hysteresis is user-adjustable too.

Figure 18 shows an application example for the logic of Figure 8. In this example FlexElements 1 and 2 (universal comparators) are used to monitor the voltage magnitude differences, while negative-sequence over-voltage function is set to monitor the unbalance. OR-gate no.1 and Timer 1 are used to complete the logic circuit. The "CCVT ALARM" flag is set to drive and output contact or alarm via communications.

8. Conclusions

The causes for CCVT failure and electricity network events were presented. From these conditions, it was possible to develop monitoring schemes and settings, which will give reliable alarms to network control centre operators for action. Various monitoring schemes suitable for three-phase and single-phase CCVTs were presented.

Microprocessor-based protection relays contain the functions necessary to perform monitoring on an incremental cost basis. Importantly, these relays provide oscillographic, event and data logging recording of voltages, which can be remotely accessed over a communication link. This enables a quick, safe interrogation of possible CCVT failure and prompt removal of plant before a possible explosion and resultant supply interruption. This information is very useful for CCVT repair and detecting generic faults due to age or inadequate design.

The benefits to an organization are improved security of supply, enhanced staff safety and continuance of reputation and goodwill with its customers. In addition, within the National Electricity Market in Australia, a considerable annual reward or penalty can be received based upon security of supply performance against specified levels.

Fig. 16.
Illustration of the sum/subtract capabilities of the universal comparator.

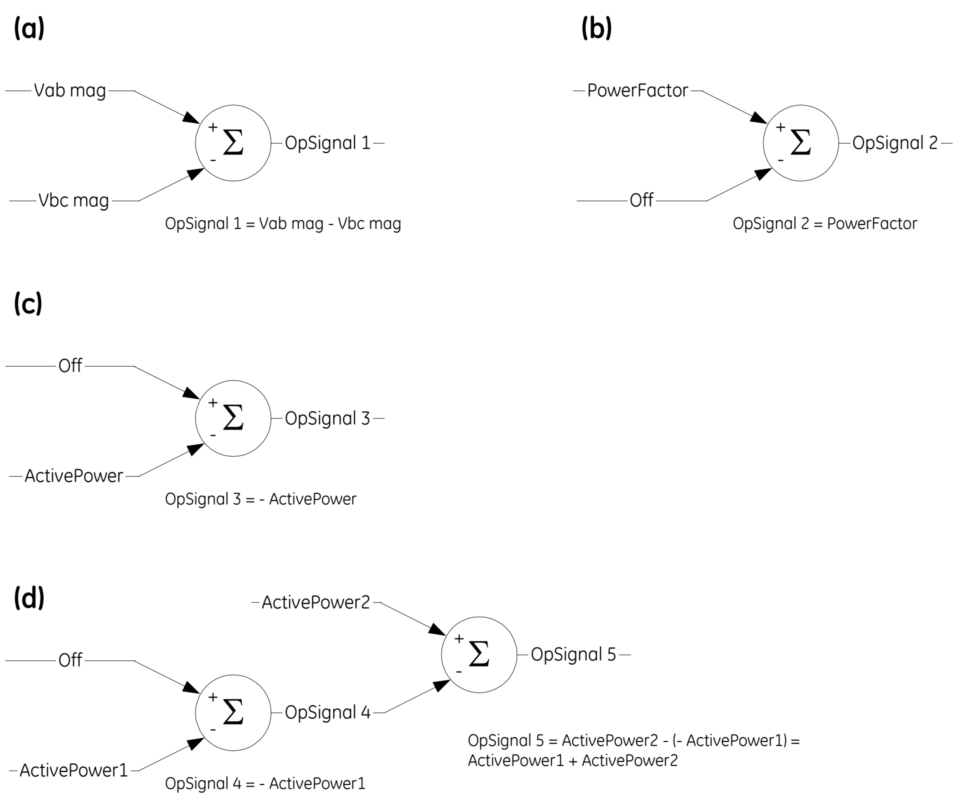


Fig. 17.
Illustration of the absolute (a) and signed (b) modes of operation. Low power factor alarm (a), and low power factor lagging, and leading alarms (b).

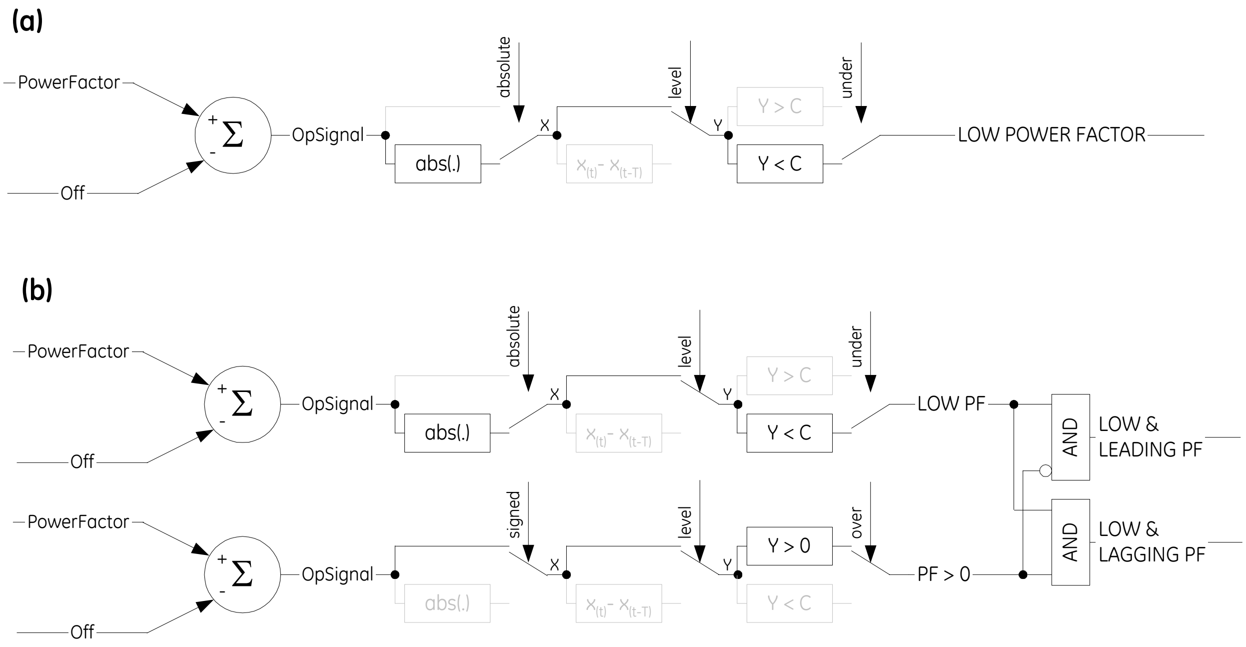
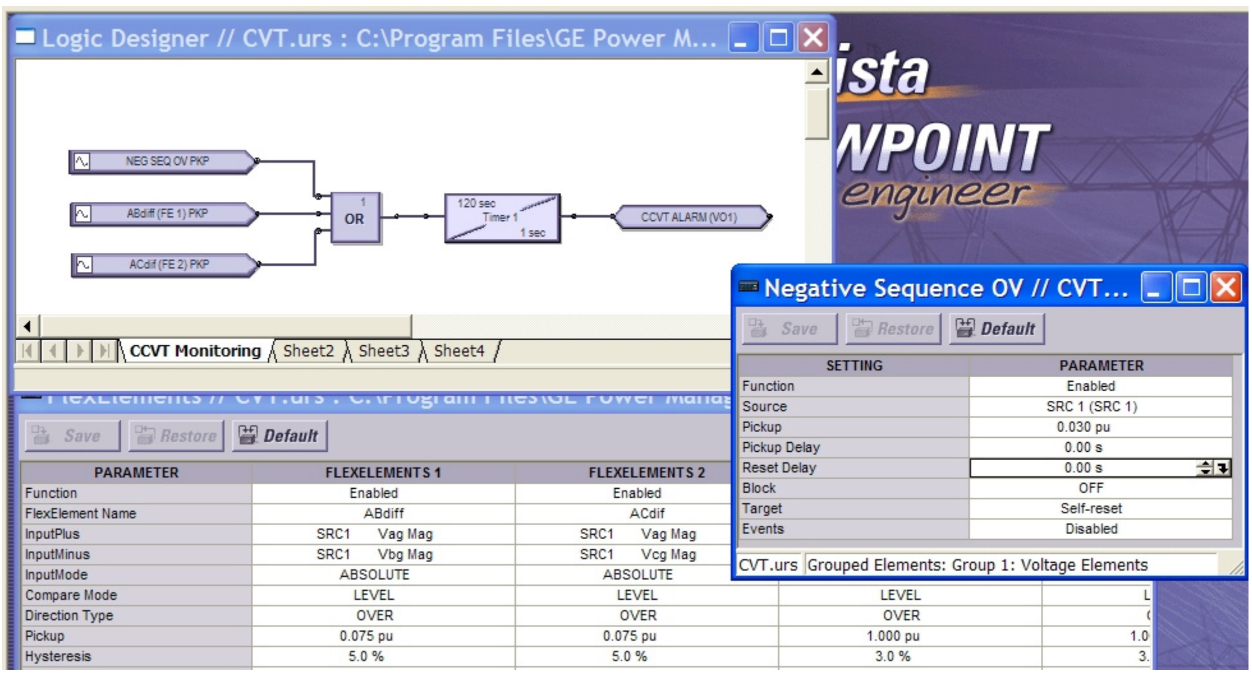


Fig. 18.
Settings implementing the monitoring logic of Figure 8.



9. References

[1] Tanaskovic M., Nabi A., Misur S., Diamanti P., McTaggart R., "Coupling Capacitor Voltage Transformers as Harmonics Distortion Monitoring Devices in Transmission Systems", 2005 International Conference on Power System Transients (IPST), Montreal, Canada, June 19-23, 2005, paper 031.

[2] (Australian) NATIONAL OCCUPATIONAL HEALTH AND SAFETY COMMISSION ACT 1985, (http://www.nohsc.gov.au)

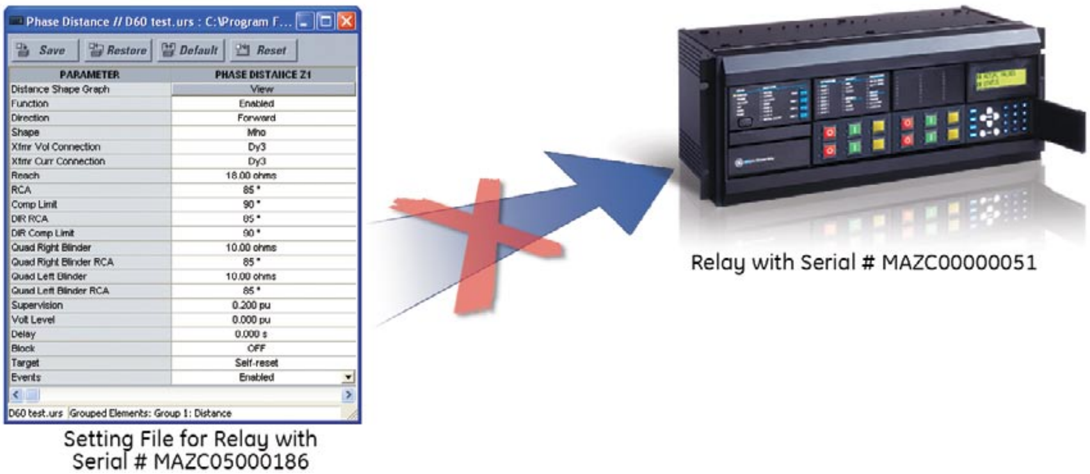
[3] Industrial Electronics Engineering P/L, Kirrawee (Australia), model 604Q relay.

[4] NEMA Standards Publication MG 1-2003, Motors and Generators, Section 12.45, Voltage Unbalance, NEMA, 2003.

Engineering Quick Tip:
Never Load Protection Settings into the Wrong Relay Again

GE Multilin has devised a method to safeguard users from erroneously sending protection settings to the wrong relay. This method, called Serial Number Locking is built into the EnerVista Setup Program that comes with GE Multilin relays.

Serial Number Locking gives users the ability to "lock" a setting file to a specific device by associating the setting file with the unique serial number of the relay. Once the setting file is "locked" to that relay's serial number, it cannot be sent to any other relay. This feature offers users the security of knowing that the proper settings are being loaded into the proper relay.

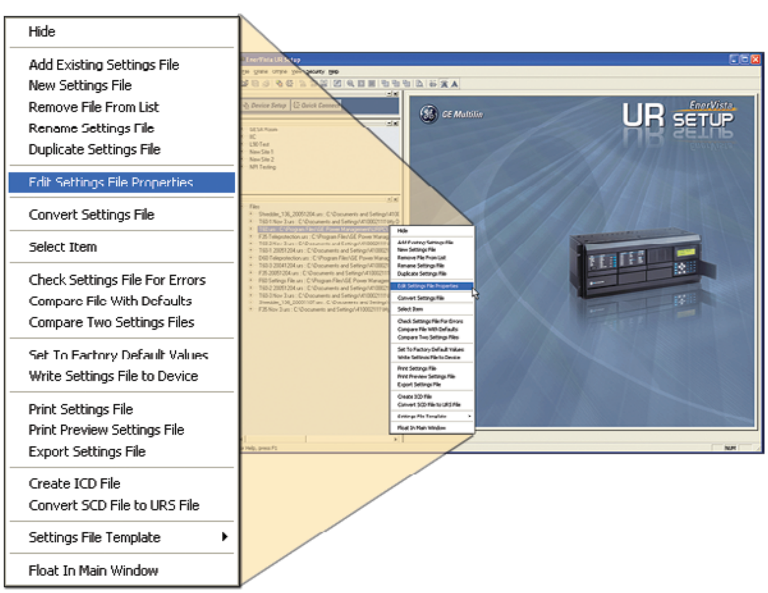


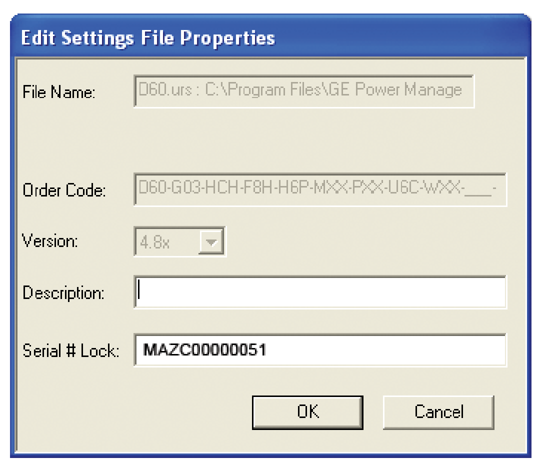
EnerVista™ Setup programs verify that the serial number that the setting file was created for, matches the serial number found in the relay

Here's an example of how it works:

1. Using the EnerVista Setup program for the GE Multilin product you are configuring, click on the setting file in the OFF-LINE window that you wish to assign a Serial Number to.
2. Right Click your mouse and select Edit Setting File Properties from the pop-up window.
3. In the window that appears, enter the Serial Number of the relay that this setting file is intended for in the field labeled Serial # Lock.
4. Click on the OK button. This setting file has now been "locked" to that relay.

When a file that has a Serial Number Lock enabled is sent to a relay, the file will only be loaded into the relay if the two serial numbers match. If the two serial numbers do not match, loading of these settings will not be permitted.





Tip: The serial number of the relay can be found on the label on the rear of the relay or by using the keypad on the front of the relay, located under Actual Values, Product Information.

Engineering Quick Tip:

Connect your Protection and Metering Devices to your Corporate Network

Many industrial facilities have protection and metering devices monitoring their electrical equipment but only access the information found in these devices by plugging a laptop computer in the serial port on the front of the device. The following simple procedure will demonstrate how to connect these devices to your corporate network so that you can access these devices from your desktop.

Fig.1. *Daisy-chaining up to 7 devices to one MultiNet Converter provides generally accepted communication response times.*

1. Connect your Serial Modbus devices to a MultiNet Serial to Ethernet converter by daisy-chaining the RS485 communications ports of your devices together and then finally to your MultiNet converter. See Fig.1.

2. Plug one end of a RJ45 Ethernet cable into the network port of the MultiNet Serial to Ethernet Converter and the other end of the cable into your company's Ethernet network.

3. Start up the MultiNet EnerVista Setup Software that can be found on the product CD that comes with the MultiNet unit or can be downloaded from the GE Multilin website.

4. In the window that appears, copy the MAC Address found on the back of the MultiNet converter into the field labeled MAC Address. (*A MAC Address is a 12 digit number that is unique to each Multinet device i.e. A2-15-B3-34-BF-16)*

5. From your company's Network Administrator, obtain a "Static IP Address", a "Subnet Mask", and a "Gateway IP" Address.

6. Enter this information in the fields labeled IP Address, Subnet, and Gateway respectively. See Fig.2.

7. From the Baud Rate pull down menu, select the baud rate that the serial devices are configured to communicate. Note that all of the devices on the RS485 daisy-chain must be configured to communicate at the same baud rate.

8. Press the Save button to send these settings to the MultiNet device.

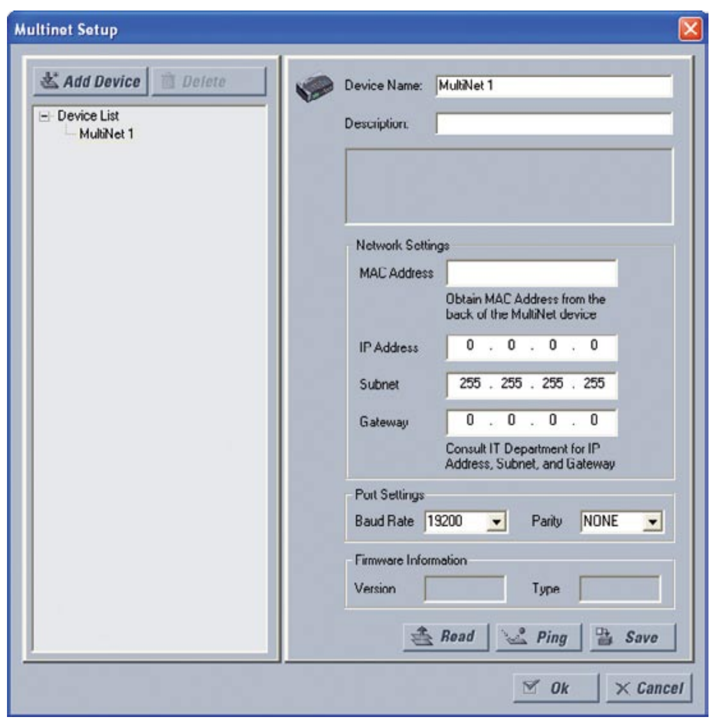


Fig.2. *Enter the IP Address, Subnet Mask and Gateway Address of the MultiNet.*

To now communicate with your devices from your desktop using the EnerVista Setup program or the Viewpoint Monitoring software, follow the instructions below.

1. Click on the Device Setup button to configure the communication settings.
2. Press the Add Device Button.
3. In the field labeled IP Address, enter the IP Address of the MultiNet that your device is connected to. See Fig.3.
4. In the field labeled Slave Address, enter the Modbus Slave address that is programmed in to this device. *(Each device that is connected in an RS485 daisy-chain must have it's own unique Modbus Slave address.)*
5. Press the Read Order Code button and press OK.

You are now ready to communicate with your GE Multilin devices from anywhere you have an Ethernet Connection.

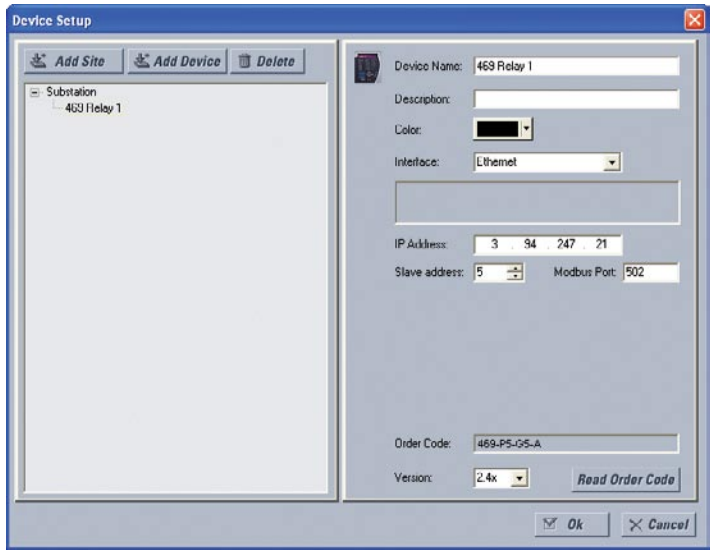
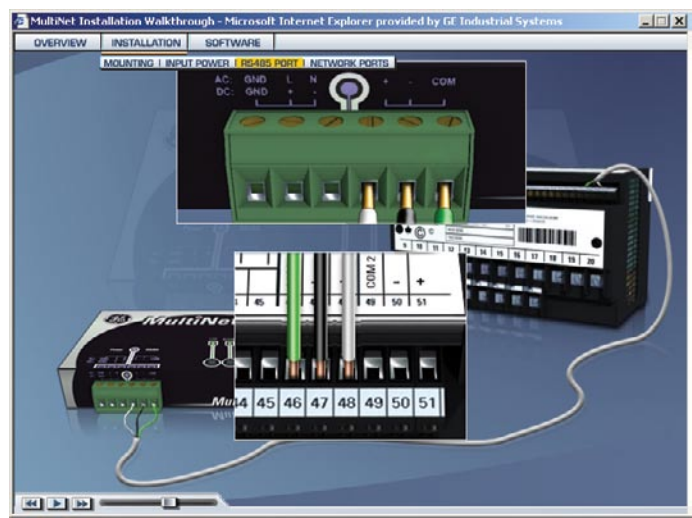


Fig.3. *Communicate to your device using the IP Address of your MultiNet and the Modbus Slave address of your relay or meter*

Tip:
If you are concerned about unauthorized users accessing these devices now that they are on your network, program the passwords on your devices to limit their access from unauthorized users.

For more Information view the MultiNet Installation Walkthrough
www.GEMultilin.com/MultiNetInstallation



Engineering Quick Tip:

Ensure all Critical Fault Data is Always Retrieved

When a fault occurs in your power system, there is some key information that quickly needs to be retrieved to help determine the cause. Viewpoint Maintenance will allow the user to gather and archive all of this critical information with a Single-Click of the mouse. The information that will be collected by Viewpoint Maintenance includes:

- Relay Type
- Relay Order Code
- Relay Firmware Version
- Setting File
- Oscillography or waveform captures
- Event Record
- Fault Reports
- Data Logger

The following procedure will demonstrate how to easily collect all critical fault information:

1. Plug your computer into the serial port found on the front of your relay, or connect your computer to the same Local Area Network (LAN) as your relay.

2. On the Viewpoint Maintenance main page, click on the menu item labeled Fault Diagnostic. See Fig.1.

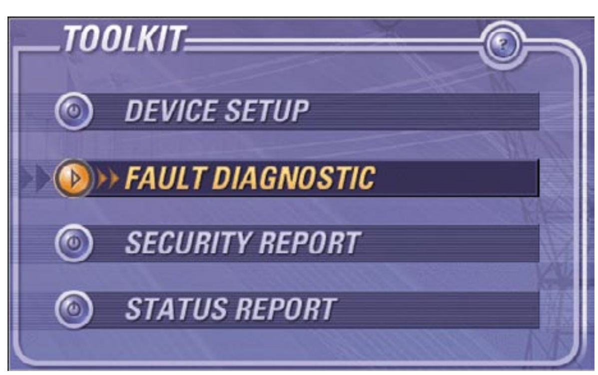


Fig.1. *Viewpoint Maintenance main page*

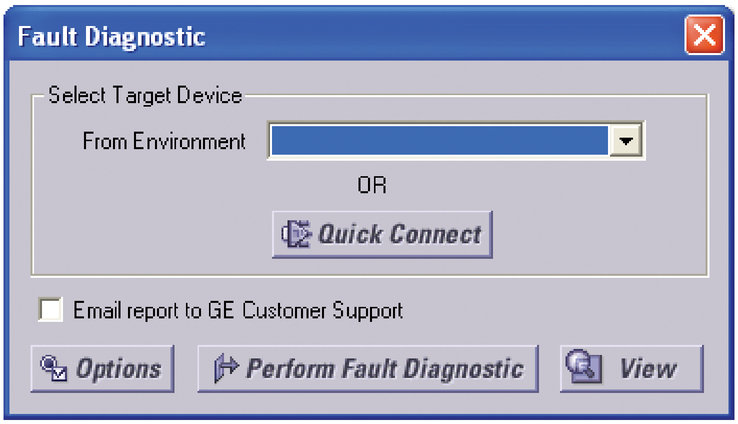


Fig.2.

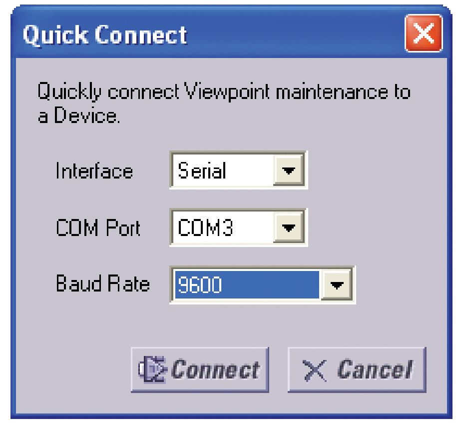


Fig.3.

3. Press the Quick Connect button and enter the communications information to match that of the relay you need to diagnose. Press the connect button. See Fig.2. and Fig.3.

4. Press the Perform Fault Diagnostic button.

Viewpoint Maintenance will systematically retrieve and archive all of the information listed on the previous page and then allow you to view all of this information on the included fault analysis viewers. See Fig.4.

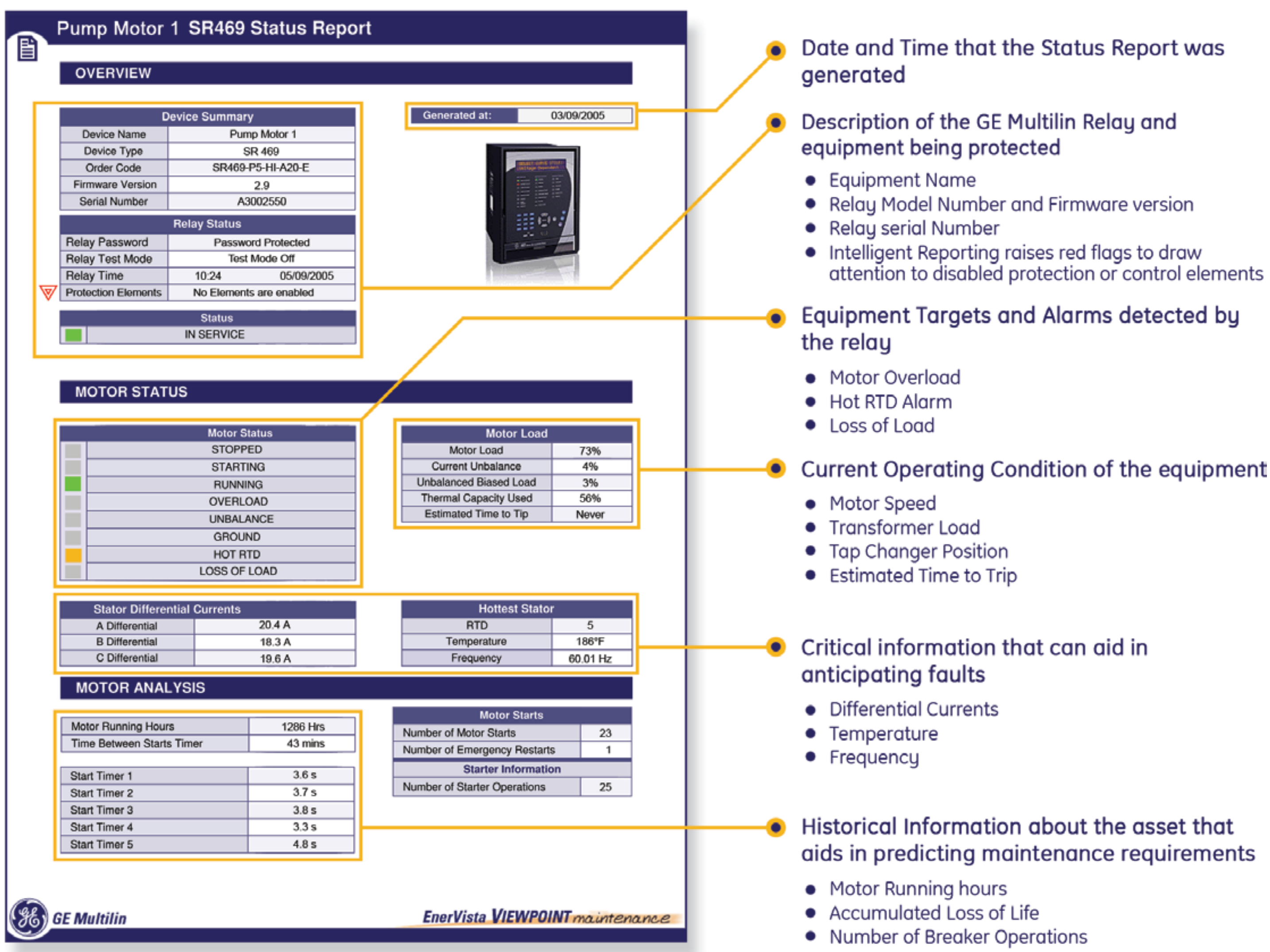


Fig.4. *The information retrieved by Viewpoint Maintenance includes a report that indicates the current status of your relay and protected equipment.*

The Viewpoint Maintenance software package provides several other easy to use reports that help you determine the current or historical operating conditions of your devices. The Settings Audit Trail report shown in Fig.5. provides you with information about setting changes that have been made to your relays. The information found in this report includes when setting changes have been made, who changed them, and what changes were made at that time.

EAST LANE 2 SECURITY/CHANGE HISTORY REPORT

Generated at: Sep 09 2005 14:30:40

Device Summary

Device Name:	East Lane 2
Device Type:	UR L90
Order Code:	L90-H03HDH-H6A-WYC
Firmware Version:	4.60
Serial Number:	MAGC0400000127
IP Address:	3. 94.247.167

Settings Summary

Setting File Name:	FAST_LINE-2.urs
Last Changed:	Sep 09 2005 14:18:03.070200 via Ethernet
Changed by Whom (MAC Address):	0008742D6FD0

Setting Changes History

Event	Date of Change	# of Changes	Password Entered	Method of Change	Changed by Whom (MAC address)	Filename Uploaded	Status	Firm. Version
144	09/09/05 02:18 PM	15	No	Ethernet	0008742D6FD0	FAST_LINE-2.urs	In Service	4.60
143	08/26/05 09:15 AM	1	No	Keypad			In Service	4.60
142	08/25/05 08:29 AM	1	No	Keypad			In Service	4.60
141	08/25/05 06:02 AM	1	No	Keypad			In Service	4.60
140	08/24/05 09:45 AM	18	No	Ethernet	00B0D0D2EA63	FAST_LINE-2.urs	In Service	4.60
139	08/09/05 05:12 AM	3	No	Ethernet	00B0D0D2EA63		Out of Service	4.60
138	08/09/05 03:12 AM	16	No	Ethernet	00B0D0D2EA63		Out of Service	4.60
137	09/09/05 02:30 PM	22	No	Ethernet	0008749784BF		Out of Service	4.60
136	09/09/05 02:30 PM	12	No	Ethernet	0008749784BF		Out of Service	4.80
135	09/09/05 02:30 PM	3	No	Ethernet	00B0D0D2EA63		Out of Service	4.60

Setting Changes Detail History

Event	Date of Change	Old Value	New Value	Item	Modbus Address
144	09/09/05 02:18 PM	Disabled	Enabled	Thermal Model Events	0x6620
144	09/09/05 01:10 PM	Disabled	Enabled	Thermal Model Function	0x6620
144	09/09/05 12:45 PM	Disabled	Enabled	Acceleration Events	0x6900
144	09/09/05 12:10 PM	10.00s	9.00s	Acceleration Time	0x6900
144	09/09/05 11:05 AM	Disabled	Enabled	Acceleration Function	0x6900
144	09/09/05 03:05 AM	Not Programmed	Programmed	Relay Programmed State	0x43E0
144	08/24/05 09:49 AM	None	F5	Source x Auxiliary VT	0x458A
144	08/24/05 03:05 AM	None	F5	Source x Phase VT	0x458A
144	08/24/05 01:12 AM	None	F1	Source x Ground CT	0x458A
144	08/23/05 11:20 PM	None	F1	Source x Phase CT	0x458A
144	08/23/05 09:10 PM	None	F5	Source x Auxiliary VT	0x4583
144	08/23/05 06:33 PM	None	F5	Source x Phase VT	0x4583
144	08/23/05 04:15 PM	None	F1	Source x Ground CT	0x4583
144	08/23/05 02:21 PM	None	F1	Source x Phase CT	0x4583
144	08/23/05 02:02 PM	1.00:1	24000.00:1	Phase VT x Ratio	0x4502
143	08/23/05 01:10 PM	1A	65000A	Phase CT x Primary	0x4480
142	08/23/05 12:30 PM	Off	SRC 2 Pc	Data Logger Channels	0x418C
141	08/23/05 11:21 AM	Off	SRC 2 Vcg RMS	Data Logger Channels	0x418A
140	08/23/05 11:01 AM	Off	SRC 1 Vbg RMS	Data Logger Channels	0x4188
140	08/23/05 10:10 AM	Off	SRC 2 V_1 Angle	Data Logger Channels	0x4186
140	08/23/05 06:19 AM	Off	SRC 1 Vca RMS	Data Logger Channels	0x4184

GE Multilin EnerVista VIEWPOINT maintenance

Date and Time that the Security Report was generated

Description of the GE Multilin Relay

- Equipment Name
- Relay Model Number and Firmware version
- Relay Serial Number

Summary of the last time the configuration was changed

- Name of setting file
- Who loaded the file
- When the file was loaded

History of last 10 occurrences the configuration was changed

- Date and time of configuration change
- Number of settings changed at this time
- Method used to change the relay settings
- MAC address of computer sending settings
- Name of the setting file sent to the Relay
- The relay status after the settings changes

Detailed description of all changes made to the relay's configuration

- Date and time of configuration change
- Description of the setting that was changed
- Setting value before change was made
- Setting value after change was made

Convenient File Format

- On-line and off-line copies
- Easily zip these reports with other pertinent files such as setting files and fault reports to share with engineers

Fig.5. *Easily track any configuration changes that have been made to you relays.*

To download a no charge 15 day trial of Viewpoint Maintenance visit www.GEMultilin.com/EnerVista

Engineering Quick Tip:

A Quick and Easy Way to Label Your Relay's LEDs

Properly labeling the LEDs on the front panel of your Universal Relays is critical to ensure Relay Technicians can quickly identify the cause of any faults. The following procedure will show you how to use Viewpoint Engineer to automatically create professional looking LED labels that are generated to match the settings that are driving each LED.

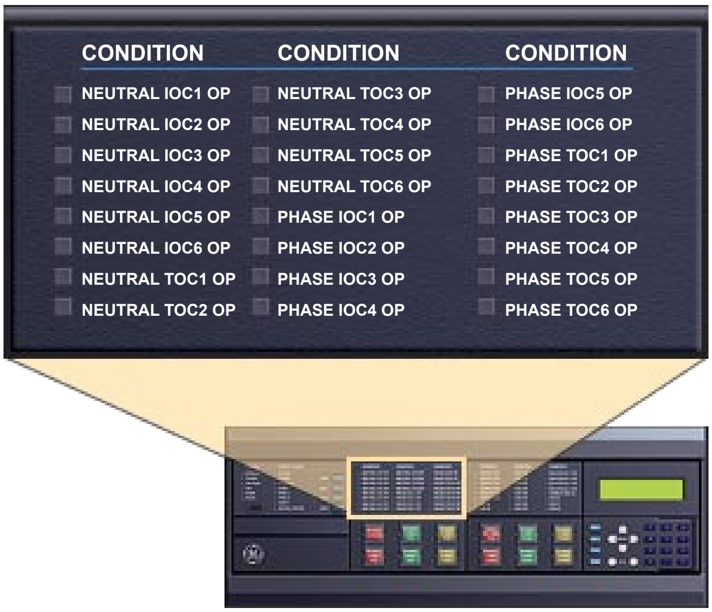


Fig.1.

Here's how it works:

1. Import an existing UR Setting File into the Viewpoint Engineer environment by selecting Open File from the File menu on the top toolbar and selecting the appropriate file.

2. Expand this file's menu tree and double-click on the Front Panel Report menu item. See Fig.2.

Viewpoint Engineer will now create a label that is populated with the names of the Flexlogic operands that are driving each LED. (i.e. Phase TOC 1 OP)

3. Print out the report that is generated by Viewpoint Engineer. See Fig.3.

4. Cut out the labels that have been created for each LED panel and remove the white strips in the middle of the labels for the LEDs to shine through.

5. Place these labels behind the clear protective cover. *(The second sheet on the Front Panel Report will step you through the process of installing these labels behind the clear protective covers)*

These reports also create the labels for the Front Panel Pushbuttons if your relay is equipped with this option. These labels are also based on the settings that are programmed in the relay setting file.

6. Cut out the label generated for each pushbutton.

7. Place the label behind the clear protective cover provided for each button.

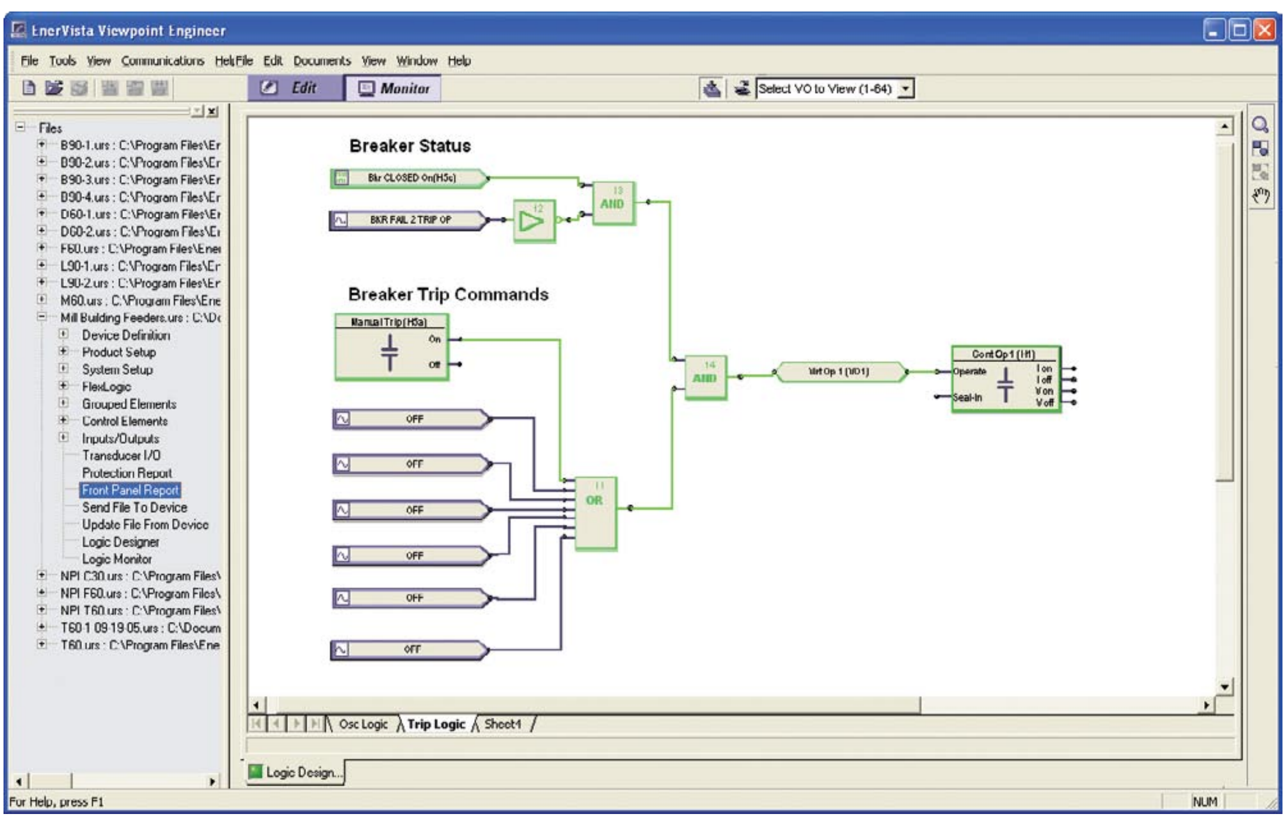
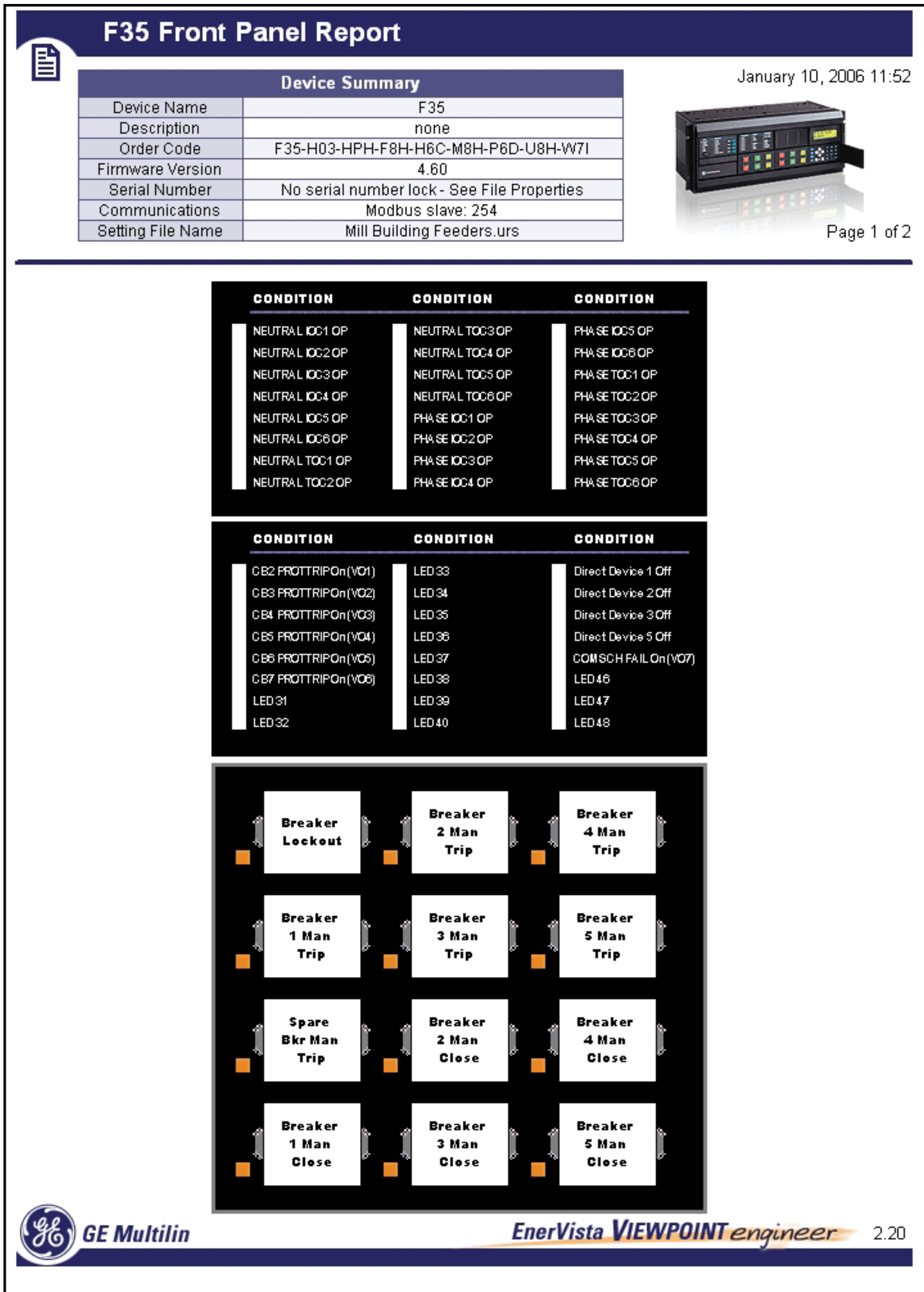
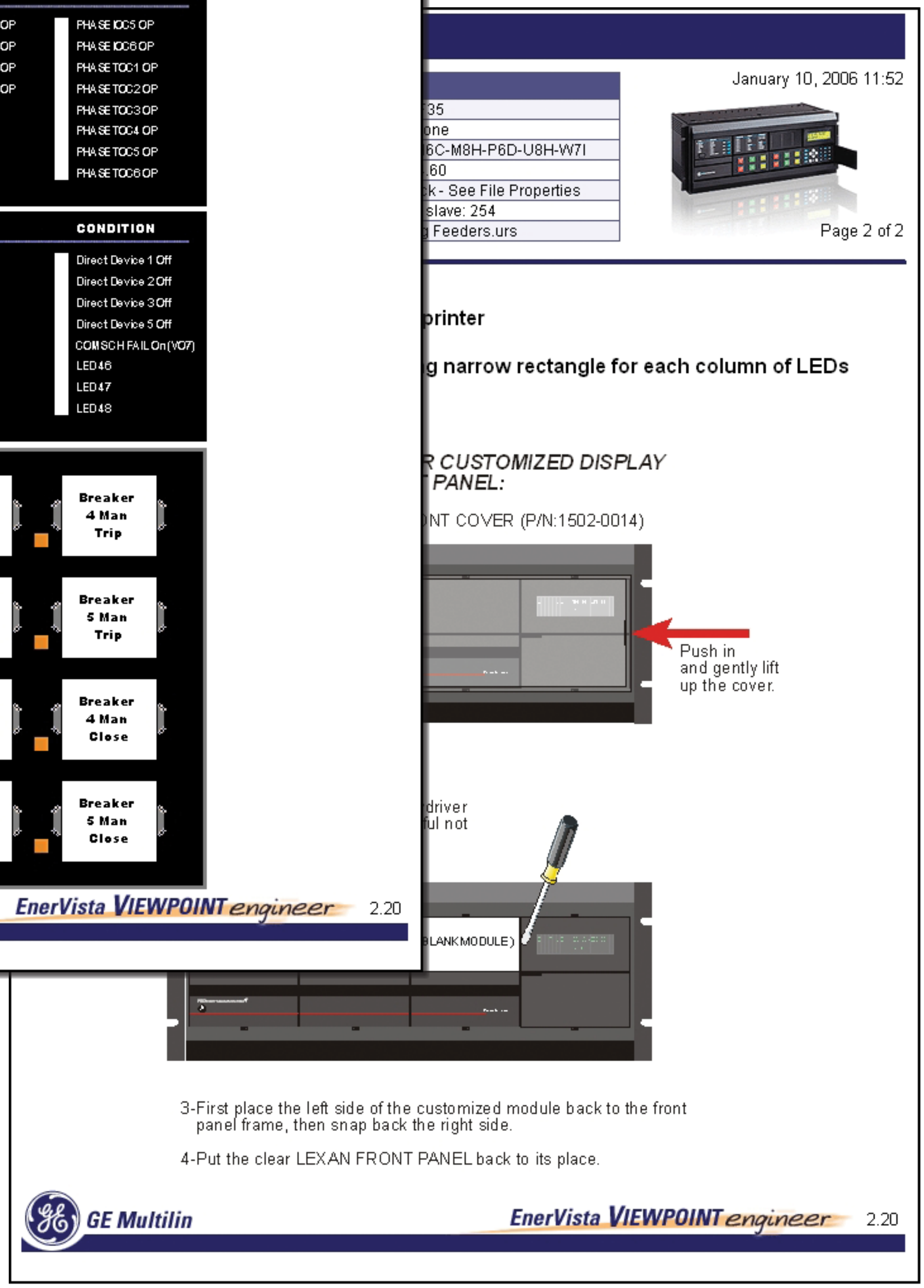


Fig.2. *The Front Panel Report in Viewpoint Engineer will analyze your Setting files and create labels for your LEDs that are based on the settings found in your relay.*





Tip:
The Front Panel Report is provided in a format that can be edited by the user to further customize these labels. Simply type in the text you wish to appear next to each LED and print out the label.

Fig.3. *Viewpoint Engineer will create labels that can be cut out and placed on your relay's front panel.*

Engineering Quick Tip:

Create a Simple Network to Monitor Your Protection and Metering Devices

Creating a communications network to remotely monitor and control your protection and monitoring devices can be done in an easy and cost effective manner. The following procedure will demonstrate how to create a communications network and begin monitoring your devices through an HMI software program.

Connecting your Network

1. If your protection or metering device is equipped with an Ethernet port, connect this port to an ML600 unmanaged Ethernet switch using a RJ45 Ethernet cable.

2. Using the keypad on the front panel of your relay or meter, program the device with an IP Address that is unique to that device. (*An IP Address is a 4 segment number that is used to uniquely identify an Ethernet device found on a network i.e. 3.94.234.27)*

3. Using the keypad on the front panel of your relay or meter, program the device with a Modbus slave address.

4. If your relays and meters do not have an Ethernet port, connect these devices to a MultiNet Serial to Ethernet converter and connect the MultiNet to the ML600 unmanaged Ethernet Switch using a RJ45 Ethernet cable. See Fig.1. (*To learn how to connect your devices to a MultiNet converter, please see Quick Tip #2)*

Fig.1.

5. If you are connecting this network to an existing network, plug your ML600 into your LAN using a RJ45 Ethernet cable.

6. If you are not connecting this network to an existing network, plug your computer directly into the ML600 using a RJ45 Ethernet cable. You will then need to assign your computer a Static IP Address. To learn how to do this, see Appendix A at the end of this quick tip.

Monitoring your Devices

To monitor your relays and meters using the Viewpoint Monitoring software program, complete the following steps:

1. Start up the software and click on the Device Setup button to configure the communication settings.

2. Press the Add Device Button.

3. In the filed labeled IP Address, enter the IP Address of the relay or meter that you want to communicate to. If you are communicating to your device using a MultiNet serial to Ethernet converter, enter the IP Address of the MultiNet. See Fig. 2.

4. In the field labeled Slave Address, enter the Modbus Slave address that is programmed into this GE Multilin device.

5. Press the Read Order Code button.

6. Press the Add Device button and complete the above steps for each additional device you are going to monitor and press OK.

7. Press the Plug and Play – IED Dashboard button found near the top of the screen.

9. Click on the device you wish to monitor and press the Dashboard button found below it. See Fig. 3.

10. Begin monitoring your relays and meters to analyze the status of your critical power system equipment. See Fig.4.

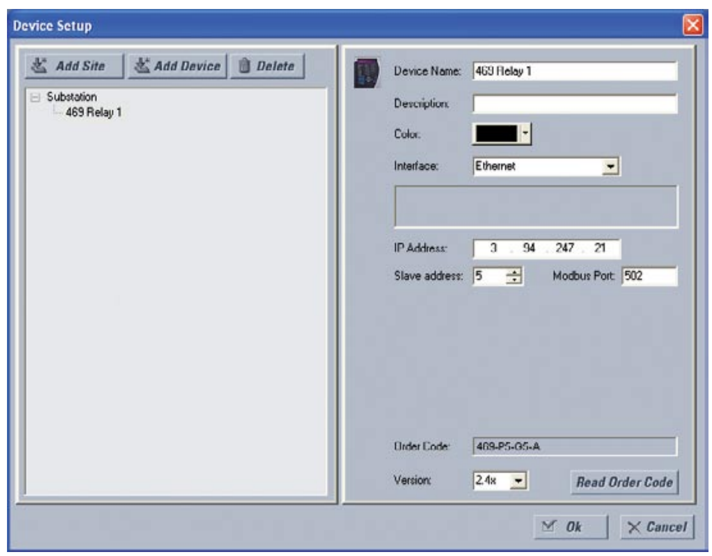


Fig.2.

Fig.3.

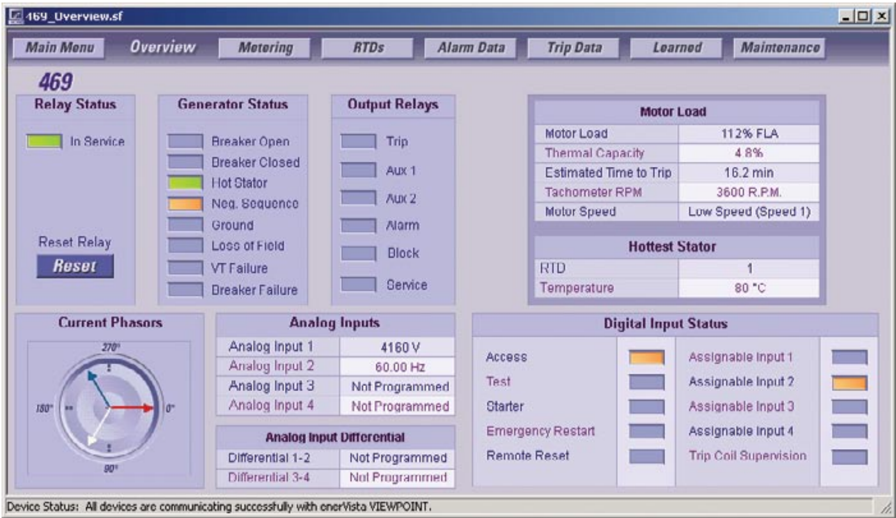


Fig. 4 *Viewpoint Monitoring will detect the devices you are using and automatically generate monitoring screens that are tailored to your devices and wiring configurations.*

Now that you can communicate with your devices, Viewpoint Monitoring will allow you to easily monitor, control, and analyze historical data about your power system using the following tools.

Single-Line Monitoring

The Single-Line Diagrams allows you to create customized Single-Line Monitoring screens that will display real-time information from multiple devices on one screen and allow for sending commands (i.e. Trip/Close) to these relays and meters. See Fig.5.

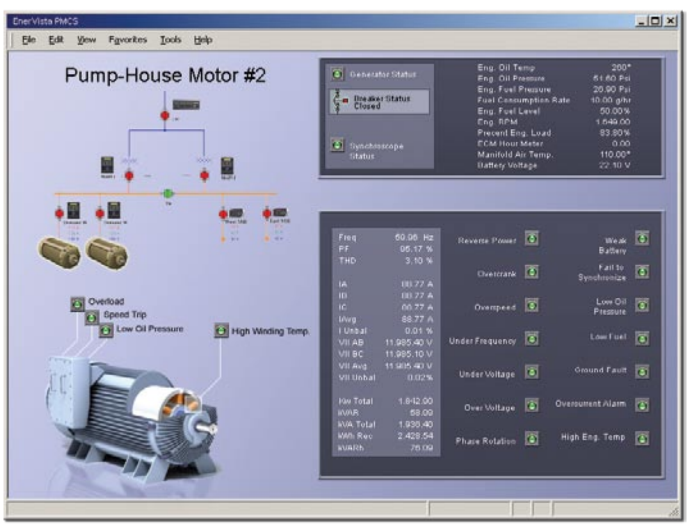


Fig.5. *Monitor the status of multiple devices to identify System problems*

Annunciator Alarming

The Annunciator Alarm screens will monitor any measured parameter and generate alarms whenever a digital value changes state (i.e. Breaker Status) or an analog value drifts beyond a preset value (i.e. Transformer Load). See Fig.6.

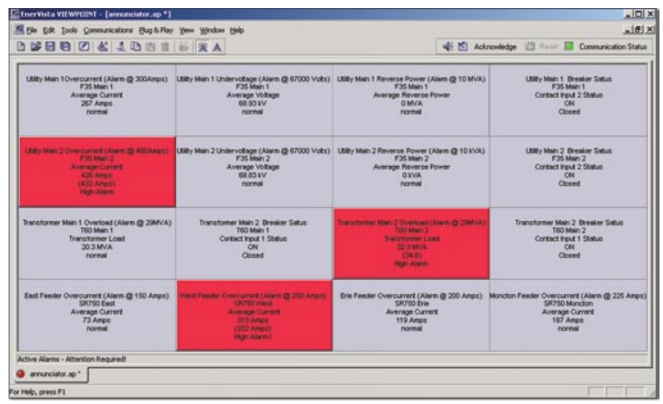


Fig.6. *Get Instant Notification of System Alarms from any device on your Network*

Trending Reports

The Trending Reports allow you to log measured parameters over long periods of time and provides a method for analyzing these values for changes over any time period. See Fig.7.

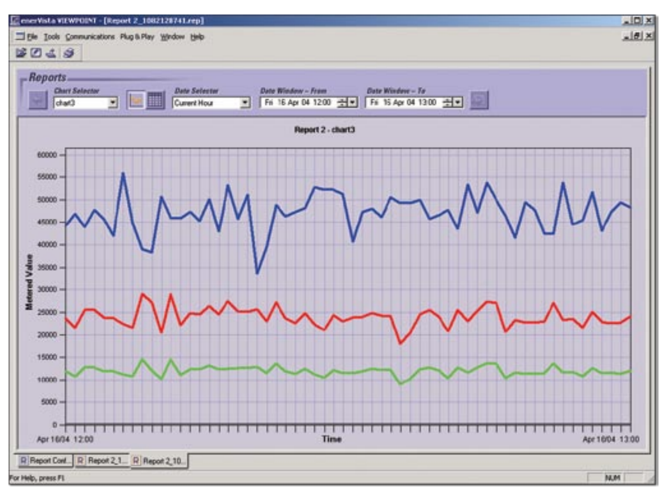


Fig.7. *Log Power Level data from multiple devices at one time*

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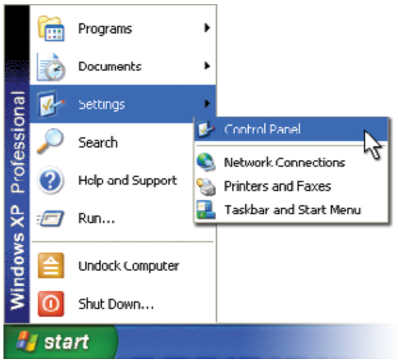
APPENDIX A

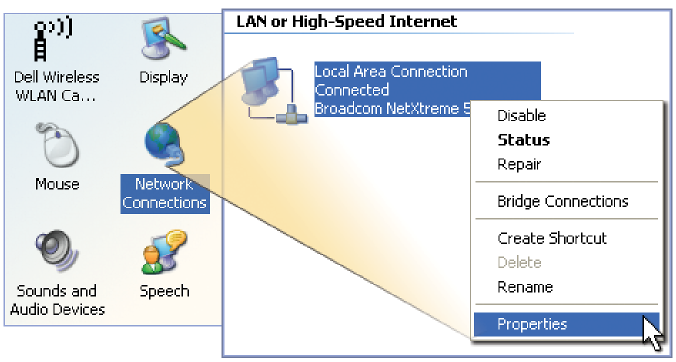
Assign your computer a "Static IP Address" that will allow your computer to communicate on your new network by performing the following steps.

1. Open your computers control panel by clicking on your Start Menu > Settings > Control Panel icon.

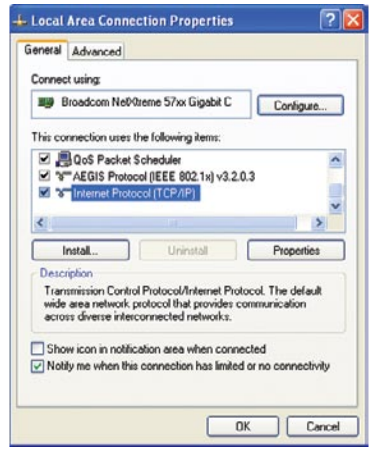


2. Double click on the icon labeled Network Connections.

3. Right Click your mouse on the icon labeled Local Area Connection and select Properties.

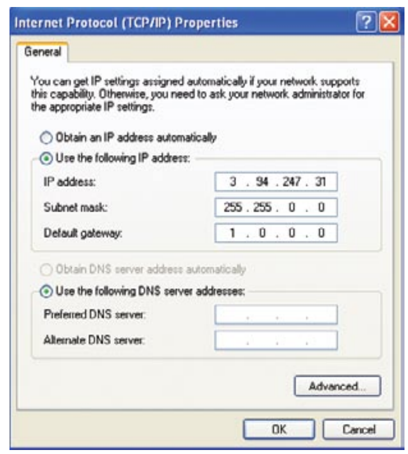


4. In the menu that appears, select the item labeled Internet Protocol (TCP/IP) and then click on the Properties button.



5. Select the tab labeled Use the following IP address.

6. Enter an IP Address, a Subnet Mask, and a Default Gateway address in their respective fields and press OK.



Tip:
The IP address for your computer must be a unique address found on this network. The subnet mask must be the same for all devices or computers found on this network. If you are unsure what number to use here, select 255.255.0.0 or contact your network administrator.

CONSULTING SERVICES

Let the experts in protective relaying ensure your power system is protected and maintained to the highest standards possible

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  - Performing System and Relay Coordination Studies
  - Developing Engineering Drawings
  - Creating Logic for your protection schemes
- **Reviewing and Validating Existing Protection Systems**
  - Analyze system and relay wiring diagrams
  - Reviewing Relay Setting Files
- **On-Site Field Services**
  - Upgrading Relay Firmware or Uploading Relay Setting Files
  - Commissioning / Field Troubleshooting
  - Arc Flash studies
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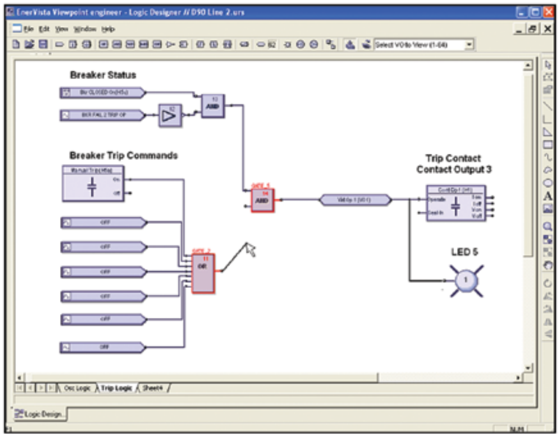

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