# Using a Real Time Digital Simulator to Model and Investigate a Phase Selection Algorithm

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ABSTRACT

The Real Time Digital Simulator (RTDS®) can be used to develop and verify faulted phase selection algorithms used for single pole tripping and reclosing schemes in high voltage transmission networks.

## I. BENEFITS OF USING A REAL TIME DIGITAL SIMULATOR

The advantage of using an RTDS is that it can both simulate/emulate the prototype relay [1] (including the phase selection algorithm) and run the test power system simulation in real time. The latter feature allows commercial relays to be connected to the same simulation for comparison purposes. A commercial relay was connected to the simulation for comparison purposes. An off-line simulation of the relay and power system using an EMTP type software package would be slower and could not interface interactively with a commercial relay. It is often not practical to interconnect all of the protection devices to the power system simulation. With inclusion of protective relay models it is possible to verify the application of specific protection schemes, including complex scenarios designed to enhance the stability of the power system.

## II. SINGLE POLE TRIP AND RECLOSE SCHEMES

Single pole trip and reclose schemes (SPTR) require accurate detection of the faulted phase at both ends of the line for proper operation. Transmission line protection must operate correctly under widely varying conditions. Pre-fault loading, fault location, type and resistance can be quite different for each event. The protective relay must operate quickly to determine the fault type and whether the fault is in its protection zone.

Transmission line protection must operate properly for faults near the bus terminals, at the remote bus, with or without series compensation. Increased fault resistance and varying load conditions must not cause a mis-operation for these types of faults. As well the directional elements in relays need to be sensitive, secure, and fast for faults in either direction.

## III. FAULTED PHASE SELECTION

Detection of the faulted phase for faults on the high voltage transmission line network in a power system is a crucial part of the relay's algorithm. Methods devised by relay manufacturers are often published without giving too much detail and may not be readily duplicated in relay models designed for real time simulations. In developing a comprehensive relay model library RTDS Technologies has investigated numerous alternative techniques for fault detection and faulted phase selection. One such method based on pre-fault and fault phase angles of voltage and current is described in this paper.

The power flow in a transmission line during normal operation controls the angle of the current with respect to the system voltage. When a fault occurs on a transmission line the angle of the current changes dramatically from the load condition to the fault condition and typically there is a large increase in the magnitude of current. The angle of the current with respect to the system voltage will be near the angle of the positive sequence impedance of the line. These three conditions can be used to effectively identify the faulted phase of the transmission line.

### A. Fault Waveforms

Fault waveforms contain a decaying exponential (DC) component dependant on the time constant of the network. A fault which occurs close to the voltage zero crossing causes the largest DC component in the current waveform resulting in possible errors in the calculation of the fundamental component (60Hz) magnitude and phase angle. Presence of a decaying exponential component causes errors in the directional element and fault selection element. Effective removal of the DC component is essential for any accurate calculation of the phase and magnitude of the fundamental component and a technique described next is shown to be simple yet effective.

### B. Fundamental Component Calculation

Calculation of the fundamental magnitude and phase angle of the voltage and current in an AC network can be accomplished with the sampled data from a buffer using a Discrete Fourier Transform (DFT). This same sampled data can also be used to calculate the DC component of the waveform. If an eight sample buffer is used, the DC component of the waveform is calculated by taking the

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difference of the 1st and 4th previous sample, or simply $sample^{n} - sample^{n-4}$. This DC value can then be subtracted from the original sample points.

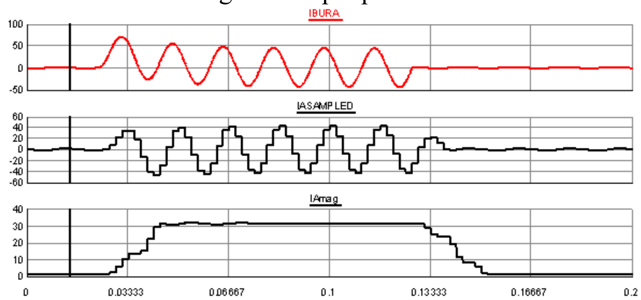


Fig. 1. Fully Offset Waveform and Fundamental Calculation with DC component removed.

### C. Phase Selection Fundamentals

The phase selection element is used to verify the faulted phase for single line to ground (SLG) fault conditions. The phase distance elements are used to detect phase to phase fault (LL) conditions and use the phase-phase voltages and currents to operate. When a single phase to ground fault is detected the phase distance elements that use this phase are blocked from operation. For example if the phase selection detects a phase A to ground fault, the AB and CA phase distance elements are normally blocked from operating. This is done because a phase distance element may falsely operate for close-up single-phase to ground faults involving one of its constituent phases and where high fault capacity exists.

### D. Phase Selection Description

The three phase voltages and currents are used to determine the fault type. The determination of fault direction and phase selection supervises the impedance elements. Two separate parts are used to properly select the faulted phase or phases. A combination of the measured angle difference between the pre–fault current and fault current combined with fault detection thresholds are done in the first part. The measured angle difference between the phase voltage and phase current is done in the second part. The combination of these two parts determines the proper phase selection [4].

### E. Phase Selection 1st part

Measured fundamental phase current angles are stored in a buffer during non-fault conditions. A fault detector comprised of the absolute magnitude of the negative and zero sequence RMS voltage is used to indicate that a fault is occurring and stops buffering of the phase currents. Before the phase selection will start there can be no open pole condition and the residual current must be above a threshold, and the individual phase currents must also be above a threshold. The phase selection firstly checks the angle difference between the pre–fault and fault currents to determine which phase is faulted. The angle limit can be adjusted between 10.0 and 40.0 degrees, and is typically set to 30.0 degrees.

TABLE I

ANGLE RELATIONSHIP BETWEEN PRE-FAULT AND FAULT CURRENT

| Phase Currents | AG Selected | BG Selected | CG Selected |
|---|---|---|---|
| IA and IA pre-fault | > 30.0 deg | - | - |
| IB and IB pre-fault | - | > 30.0 deg | - |
| IC and IC pre-fault | - | - | > 30.0 deg |

### F. Phase Selection 2nd part

The 1st part of phase selection identifies a faulted phase based upon the angle difference between the pre-fault and fault currents as well as the threshold detections for the phase and residual currents.

The relationship between the faulted phase voltage and current is determined largely by the positive sequence impedance of the transmission line. During a fault, the current should be lagging the voltage by approximately the positive sequence impedance angle of the transmission line. For SLG faults the phase selected in the 1st part is checked in the 2nd part, and if the angle difference is not within positive sequence line angle plus 40.0 deg the phase is determined not to be faulted. If the fault voltage is not of a sufficient magnitude this additional check is not performed. The two parts of the algorithm determine if more than one phase is involved in the fault and then turns off the appropriate phase to phase elements. For example if phases A and B were identified the AB phase distance element would be operational, as well as, the A and B ground distance elements, all other distance elements would be blocked.

TABLE II

ANGLE RELATIONSHIP BETWEEN FAULT VOLTAGE AND FAULT CURRENT

| Phase Voltages and Currents | AG Selected | BG Selected | CG Selected |
|---|---|---|---|
| VA and IA fault | < Z1ang+40deg | - | - |
| VB and IB fault | - | < Z1ang+40deg | - |
| VC and IC fault | - | - | < Z1ang+40deg |

### G. Distance Element Supervision

Phase to ground distance element (21N) supervision logic is formed based on the following phase selection criteria. The ground distance elements are only allowed to operate if the faulted phase is part of the element:

AG requires: no BG and no CG, or an ABG or CAG fault
BG requires: no AG and no CG, or a BCG or ABG fault
CG requires: no AG and no BG, or a CAG or BCG fault

Phase to Phase distance element (21P) supervision logic is formed based on the following phase selection criteria. The phase distance elements are only allowed to operate if the faulted phase is not part of the element:

AB requires: only CG fault has been detected
BC requires: only AG fault has been detected
CA requires: only BG fault has been detected

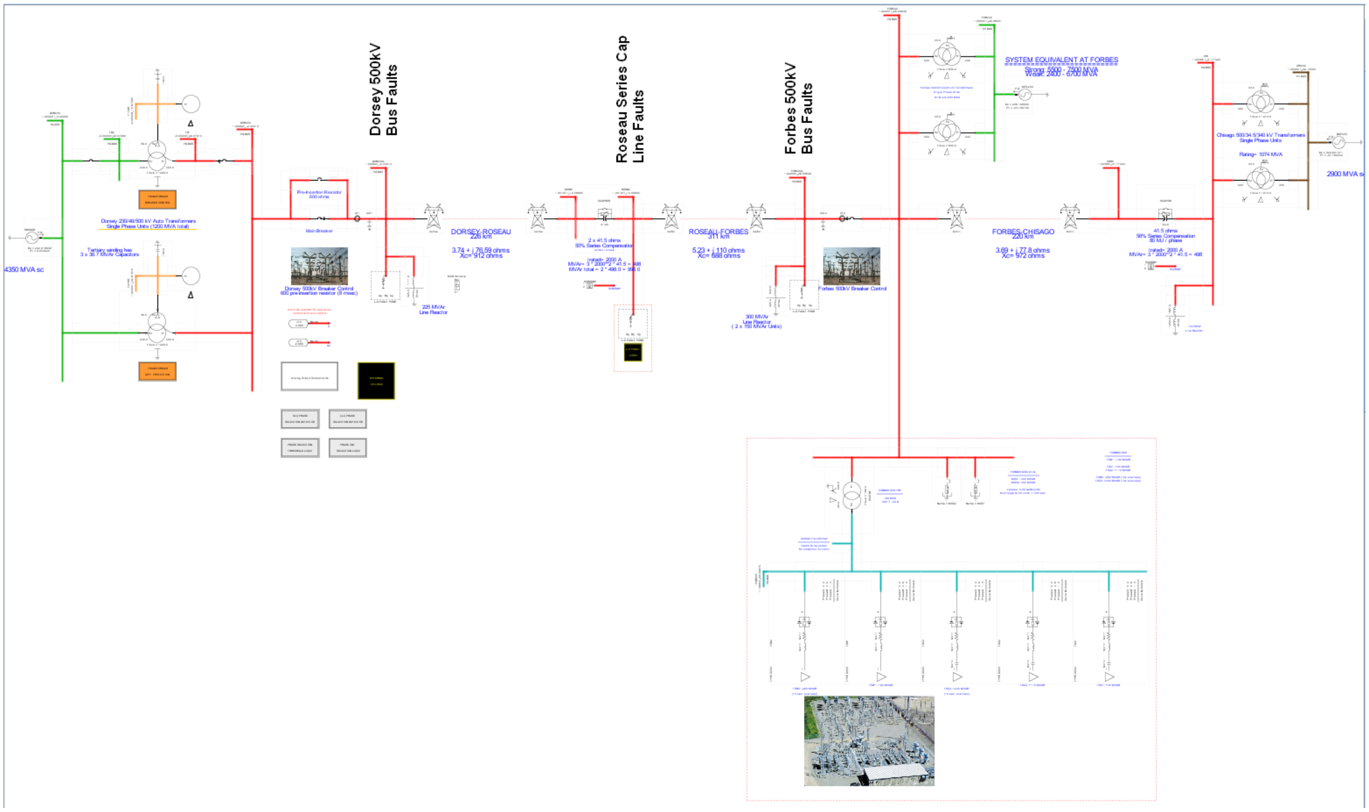


Fig. 4. Manitoba Hydro 500kv connection to Minnesota, Dorsey to Forbes Line D602F.

### H. Simulation Results without Series Capacitor

The described phase selection logic was tested using the system shown in figure 4 with the Roseau Series Capacitor bypass breaker closed [3]. The network is part of the 500kV system between Manitoba and the USA. Faults were applied at three locations, the bus location at Dorsey substation in Manitoba, the bus location at Roseau and the bus location at Forbes substation in Minnesota. SLG, LL and LLG faults at varying point on wave angles with varying fault resistances were applied

Figures 5 and 6 plot the relay element operation for a fully asymmetrical SLG fault on phase "A" applied to the Dorsey bus without the Roseau series capacitor bank in service. In Figure 5 bit 22 of the red plot is an indication that phase A has been selected. Bits 3 and 9 of the same plot are zone 1 and zone 2 phase-neutral elements being asserted. Bit 29 indicates phase A of the circuit breaker opening and then reclosing in about 1.5 seconds. The open pole logic in the relay prevents further operation of the distance elements.

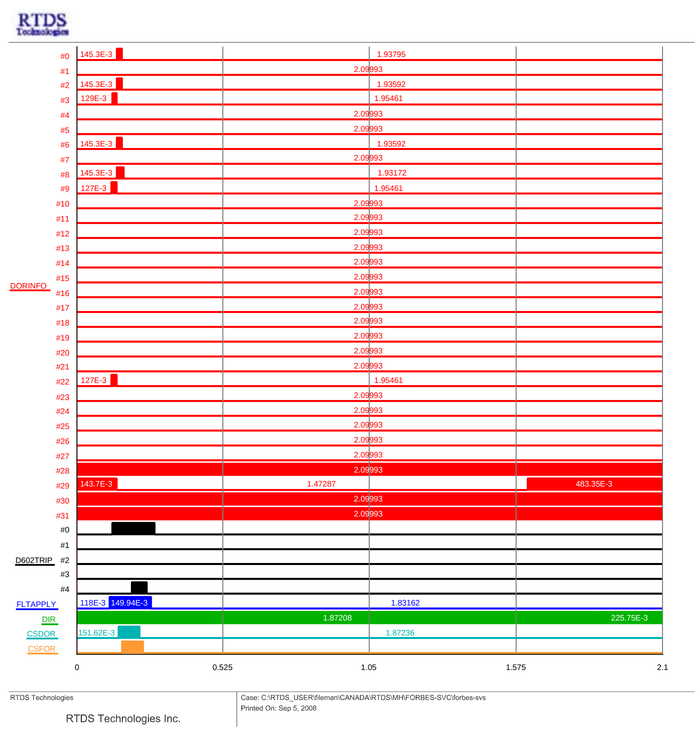


Fig. 5. Dorsey Relay Operation without Series Compensation.

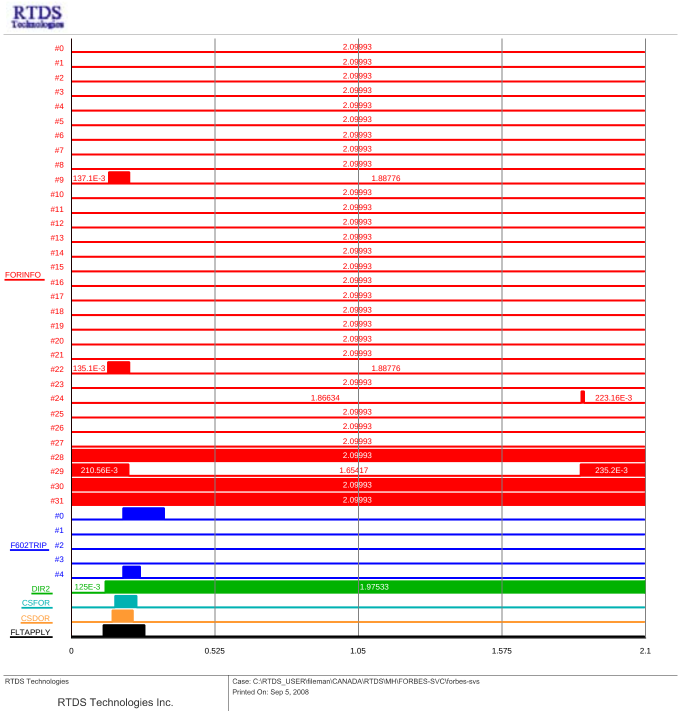


Fig. 6. Forbes Relay Operation without Series Compensation.

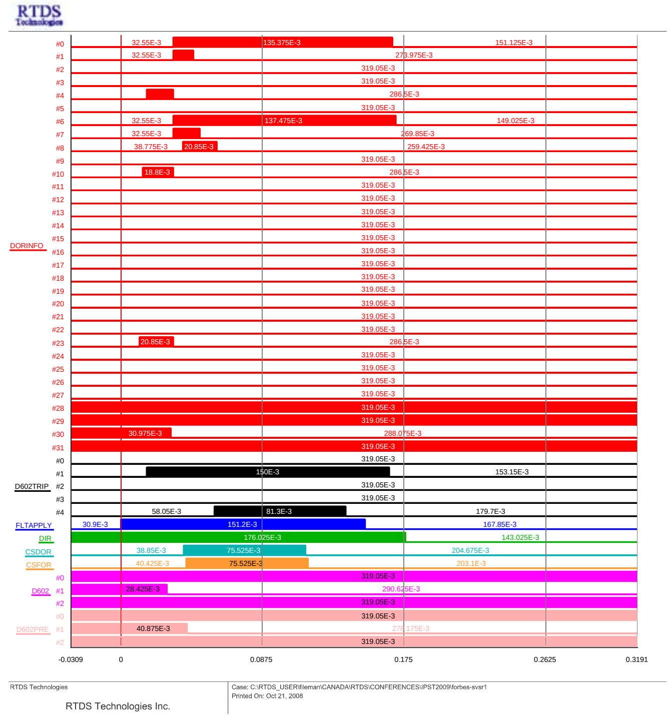


Fig. 7. Dorsey Relay Incorrect Operation with Series Compensation.

In Figure 6 bit 22 of the red plot is an indication that phase A has been selected. Bit 9 of the same plot indicates zone 2 phase-neutral elements being asserted. Bit 4 of the blue plot is the 85 element trip and asserts 35ms after the permissive signal (CSDOR) is received from Dorsey. Bit 29 indicates phase A of the circuit breaker opening and then reclosing in approximately 1.5 seconds. This is a correct operation. The relay operated correctly for all the other faults applied.

### *I. Simulation Results with Series Capacitor*

The described phase selection logic was tested using the system shown in figure 4 with the Roseau Series Capacitor bypass breaker open. The faults described above were again applied and it was noted that the phase selection algorithm would mis-operate for LLG faults at the Roseau station bus.

An ABG fault was applied at Roseau bus and the relay at the Dorsey bus was seen to mis-operate. The phase selection algorithm properly detected B phase but did not detect phase A. In Figure 7 bit 23 of the red plot is an indication that phase B has been selected. Bits 4 and 10 of the same plot are zone 1 and zone 2 phase-neutral elements being asserted. Bit 30 indicates phase B of the circuit breaker opening and then reclosing in about 1.5 seconds.

Investigation of this incorrect operation of the phase selection algorithm revealed that the series compensation would not change the angle of the fault current but rather only increase the current magnitude for certain faults. Fault currents were recorded and the results of these investigations are shown in figures 8 and 9.

The fault currents plotted in figure 8 are for the ABG fault at Roseau bus and the plot for phase A current shows the amplitude increasing with very little change in angle. This is the reason that the 1st part of the phase selection algorithm failed to operate for the point on wave angle of 345.0 deg.

The same fault was applied and the point on wave angle was then increased until the relay operated properly. Figure 9 plots the fault currents for the point on wave angle of 23.0 deg where the relay started to operate properly. The plot for phase A current shows a sharp change in the amplitude that translates to a transient change in the measured phase angle, as well as, the expected change in amplitude.

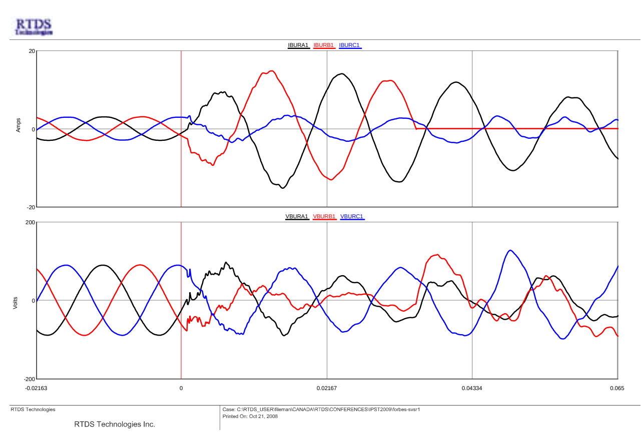


Fig. 8. Dorsey ABG fault at 345 deg POW reference to phase A voltage.

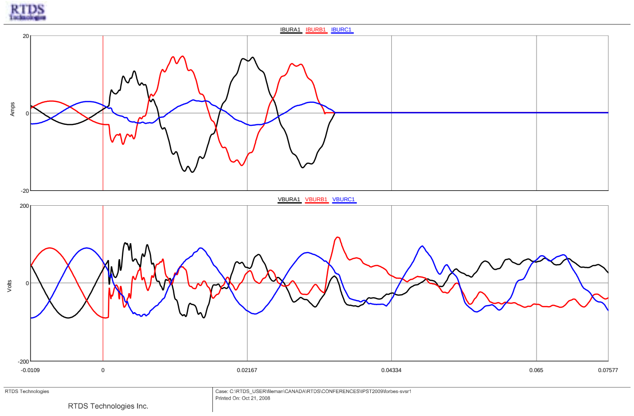


Fig. 9. Dorsey ABG fault at 23 deg POW reference to phase A voltage.

The test scenarios that were used to develop this algorithm were played back in real-time via low level analog signals to a commercially available relay [5]. Logic in the simulation enabled the relay to operate at Dorsey or Forbes during the simulation. The commercial relay did not exhibit incorrect tripping i.e. all SLG faults operated single pole and all LLG faults operated 3 pole.

## IV. Conclusions

RTDS Technologies has developed and tested this algorithm which is included in a multi-function distance relay that is part of the RTDS library. This relay has been used with other simulations and studies [2] and has been shown to provide correct operation without the presence of series compensation but it will not operate correctly with series compensation as shown in this study.

Using a real time simulator has the added benefit of being able to use the same tool to simulate the transient behavior of the test power system, emulate the behavior of the protection algorithm under investigation and provide real time signals for an externally connected commercial relay.

## V. References

*Periodicals:*

[1] J. Tang, M. Sloderbeck, D. Ouellette, P. Forsyth, J. Langston, P. McLaren, “In System Emulation (ISE) of a new Current Differential Back-up Protection Relay” DPSP Conference, Glasgow, March 2008

[2] P. G. McLaren, J. Tang, D. Ouellette, J. Langston, and P. Forsyth, "Testing Relay Systems," Nuclear Relay Conference, San Diego, pp. 6, Sept. 2008.

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*Books:*

[4] RTDS Technologies Inc., "User Manual" *Controls Library Manual*, chapter 8.4, Multi-function Distance.

[5] Schweitzer 421 Relay Manual

## VI. Biographies

**Dean Ouellette** graduated from Red River Community College in Winnipeg with a diploma in EE Technology in 1986. He has spent the past 23 years working in the field of power system protection. His employment experience includes Manitoba Hydro (1986-89), British Columbia Hydro (1989-1999), Schweitzer Engineering Labs (1999-2001), Nxtphase Corporation (2001-2003). Dean joined RTDS Technologies in 2003 and currently is the Principal Technologist / Simulator Specialist.

**Rudi Wierckx** received his B.Sc (EE) and M.Sc (EE) degrees from the University of Manitoba in 1983 and 1985 respectively. Between 1985 and 1993, he was employed by the Manitoba HVDC Research Center, working on the development of the Real Time Digital Simulator (RTDS). In 1993 he left the Research Centre to form RTDS Technologies Inc. and is currently a director of that company.

**Paul Forsyth** received his B.Sc. degree in Electrical Engineering from the University of Manitoba, Canada in 1988. After graduating he worked for several years in the area of reactive power compensation and HVDC at ABB Power Systems in Switzerland. He also worked for Haefely-Trench in both Germany and Switzerland before returning to Canada in 1995. Since that time he has been employed by RTDS Technologies where he currently holds the title of Marketing Manager / Simulator Specialist.

**P.G. McLaren** received his degrees from the Universities of St. Andrews, Cambridge and Dundee, all in the UK. He is a Fellow of the IEEE and IET and a chartered engineer in the UK and Europe (C.Eng, Eur Ing).