Using Time Error Differential Measurement in Protection Applications

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***Abstract*—Numerous problems in power system protection have led to ongoing work for protection engineers to properly configure relays and other devices. These problems include power swing blocking, power swing tripping, and islanding detection. Traditional detection of these conditions using voltage and current have led to complex algorithms and setting guidelines. Distributed generation has complicated issues by making system models more extensive while large interarea power sales and load flows have made older setting guidelines suspect.**

Time Error (TE) has been used as a basis for generation dispatch for years. Using a difference between "real time" and "system time" measured to tenths or even hundredths of a second, system frequency was adjusted and generation levels raised or lowered.

Modern Intelligent Electronic Devices (IEDs) have the capability of measuring TE to fractions of a millisecond. This level of accuracy and resolution introduces the capability of a new input to wide-area control: Time Error Differential (TED).

This paper discusses the basis of TED for use in special protection schemes such as islanding detection, generation dropping on loss of load, power swing detection, and system disturbance detection for automatic load preservation. System conditions leading to TED and comparison with alternate measurement methodologies for special protection schemes are presented.

Because TED has never been available for use, practical considerations to its application are presented. These considerations are based on both the measurement unit and the communications system available. Both high-speed control algorithms and visualization systems for human intervention are presented as possible applications.

Advances in both measurement and communications is expanding the efficiency and stability of the overall power system. The use of TED provides new tools and methods to continue to maximize the use of generation and transmission grid assets.

I. INTRODUCTION

In the early days of electricity generation and transmission, system protection consisted of men in bowler hats watching ammeters. If the current went too high, the operator pulled a large knife switch and fanned the arc out with his hat. Automatic relays using current coils and magnetic disks followed. Voltage was added as an operating quantity increasing the options for protection. Combining voltage and current gave us distance relays of all forms. Frequency was recognized as a critical quantity following the 1965 blackout in the northeastern US and eastern Canada.

On every occasion where additional operating quantities were added to those previously available, engineers have improved system and equipment protection. Widespread availability of very accurate time sources have made possible the measurement of Time Error (TE) to a much greater resolution than previously possible. TE is defined as "The integral of frequency error. Generally utilized as a measure of regulating performance for frequency regulation, Time Error can be measured as the error between a clock synchronized to the electrical system and the astronomical time kept by the National Bureau of Standards" [1]. For example, if the period of the waveform is $1/f_{nom}$ there will be no TE (TE = 0), as shown in Fig. 1. If the period is less than $1/f_{nom}$ then a clock based on the frequency would run fast and there would be a positive TE. If the period is greater than $1/f_{nom}$ then a clock based on the frequency would run slow and there would be a negative TE.

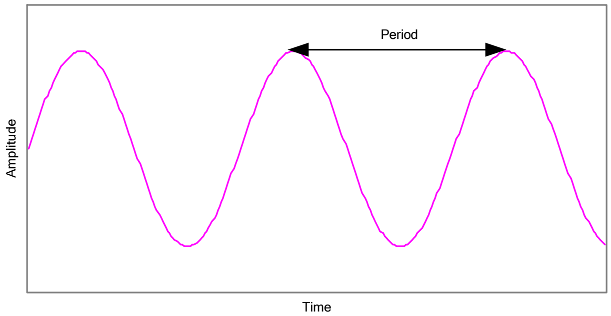


Fig. 1. Measuring Time Error Using a Periodic Waveform

There are two key elements to measuring TE in a protective relay or other substation Intelligent Electronic Device (IED). The first is highly accurate time. Testing of typical commercial clocks indicates that time is measured to between 50 and 150 nanoseconds accuracy as shown in Fig. 2 [2]. With clocks of this accuracy ranging in price between $500 and $3000, it is very practical to apply accurate time throughout any station.

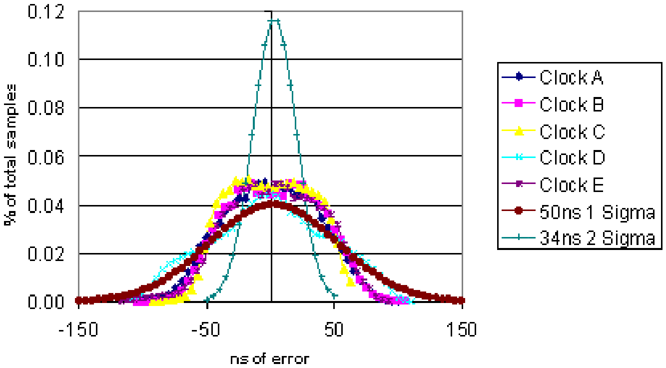


Fig. 2. Time Measurement Accuracy

The time signal is sent to the relay typically using IRIG-B signals. Accuracy is lost in transmission to the IED and inside the electronics. Timing accuracy inside IEDs such as relays is specified at ±5 µs and typical test values at ±1 µs.

Even using the "worst" value of ±5 µs, this provides an equivalent accuracy between two IEDs of just under 0.25 electrical degrees (10 µs = 0.000010 s * 60 cycles/s * 360°/cycle = 0.216°). This is clearly beyond the accuracy needed for most practical applications.

The second component used to measure TE is the measure of time synchronized to the electrical system. Using a combination of zero crossings and frequency measurement, time is measured to an accuracy of better than ±5 µs.

The combination of accuracy of time measurement, both by satellite clock and frequency clock, leads to a TE measurement accuracy of 10 µs. This is an improvement of earlier TE measurements that at best measured to the tenths of a second by a factor of 100,000. Where TE was used for frequency control, we can now use the more precise measurement of TE as a measurement tool to determine and analyze power system conditions.

II. TIME ERROR DIFFERENTIAL (TED) MEASUREMENTS

As a measurement of the integral of frequency deviations from nominal, TE, at a single point, can provide useful information about frequency stability and load-generation balance. Comparing the TE at multiple locations and evaluating the differences between them, or TED, can provide additional information.

In order to compare TED with other system measurement tools, such as phase angle and frequency, we used a model power system as shown in Fig. 3.

Phasor Measurement Control Units (PMCUs) can be used to evaluate system performance during fault conditions [3]. Phase angle and frequency during fault conditions can be compared from all over the system to provide a powerful visualization tool. Adding TED to this analysis provides, in some instances, a more useful method of determining control points and assisting operators in understanding conditions. On the system in Fig. 3, the prefault load on Bus 4 is changed for three different cases. By increasing the prefault load on the system, a fault on L3 is followed by a fully damped oscillation, a critically damped oscillation, and finally by a growing oscillation that causes a system separation. In the simulation, we only look at TE, phase angle, and frequency transmitted from each PMCU. PMCUs in an actual system have information on breaker state, which could also be included in a data transmission. We have not done that in this case. An actual power system has connections that may not be part of the data collected. These are included in our model as Line 4, which is a connection without control.

The data is collected using the IEEE C37.118 synchrophasor message format. This includes provision for phase angle, frequency, and other analog values. In this case, the TE from each PMCU is transmitted as an analog value. In the case of the stable fault, the three values can be seen on one screen as shown in Fig. 4.

In this case, the phase angle plot clearly shows that the postfault system is stable with a well-damped oscillation. Note that the TE at the different locations has changed as a result of the redistribution of load, changing the load angles on each line. This results in a change in TE of about 3 ms between locations. For conditions following the stable fault, note that the phase angle plot, shown in the lower left portion of Fig. 4, shows the differences in phase angle much clearer than the time error. This could bring up the question "Why bother with TE when phase angle shows the picture better?"

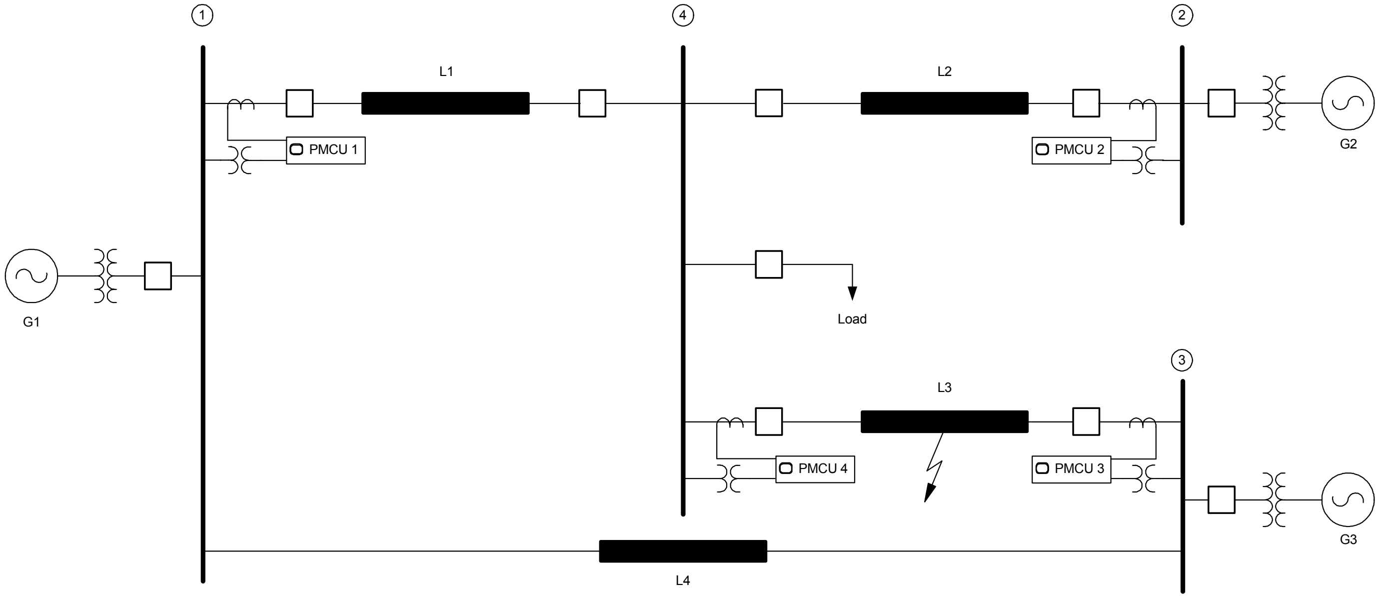
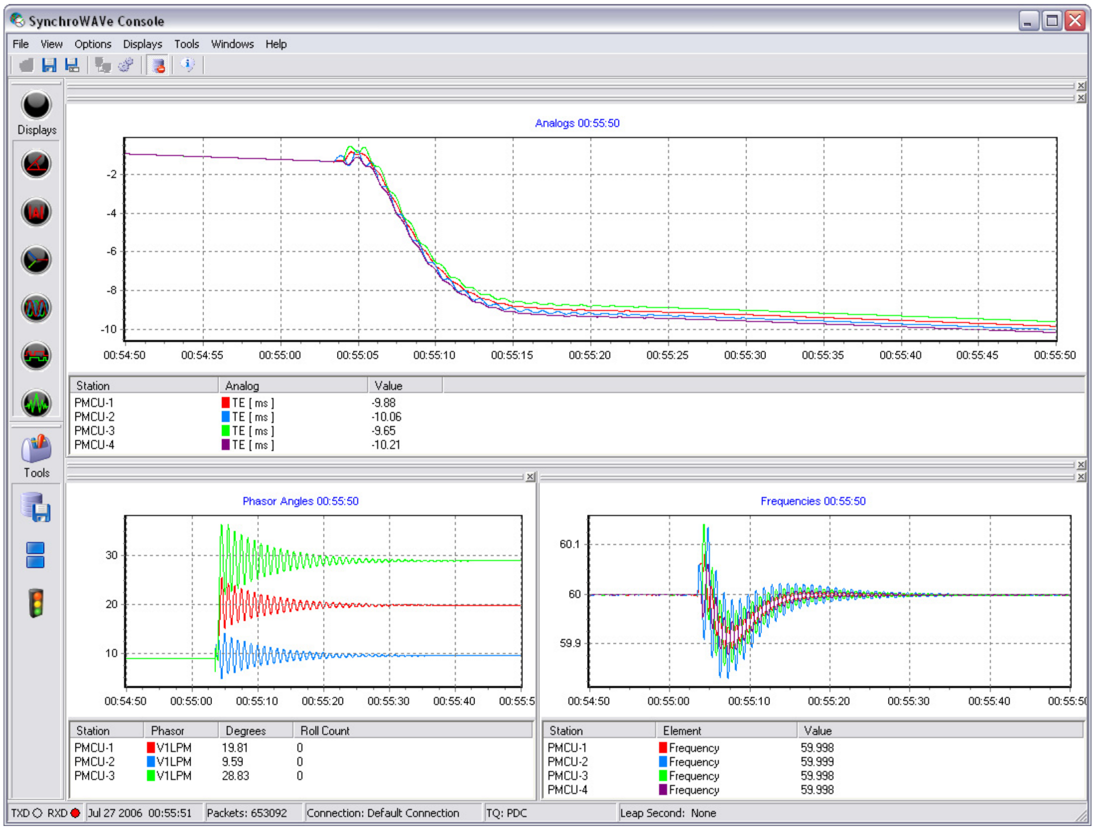


Fig. 3. Model Power System With Three Sources and Four Phasor Measurement Control (PMCU) Units



Station	Analog	Value
PMCU-1	🟥 TE [ms]	-9.88
PMCU-2	🟦 TE [ms]	-10.06
PMCU-3	🟩 TE [ms]	-9.65
PMCU-4	🟪 TE [ms]	-10.21

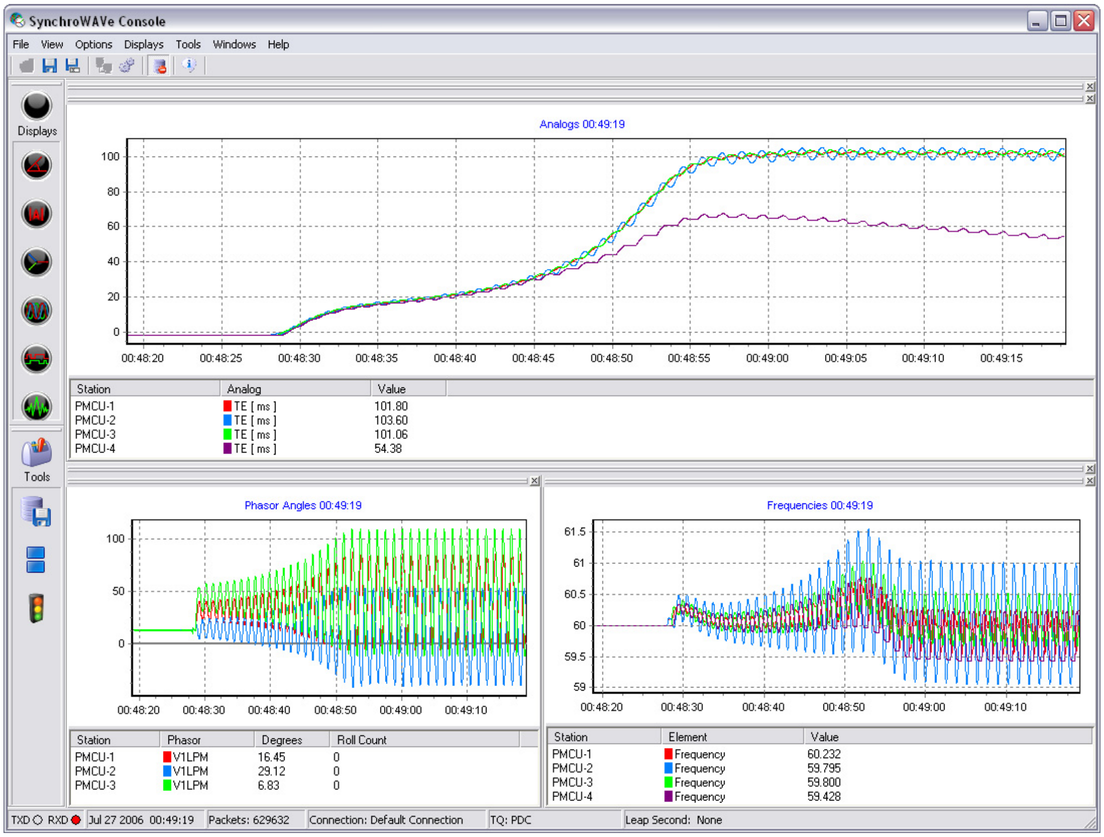
Station	Phasor	Degrees	Roll Count
PMCU-1	🟥 V1LPM	19.81	0
PMCU-2	🟦 V1LPM	9.59	0
PMCU-3	🟩 V1LPM	28.83	0

Station	Element	Value
PMCU-1	🟥 Frequency	59.998
PMCU-2	🟦 Frequency	59.999
PMCU-3	🟩 Frequency	59.998
PMCU-4	🟪 Frequency	59.998

TXD ○ RXD ● Jul 27 2006 00:55:51 Packets: 653092 Connection: Default Connection TQ: PDC Leap Second: None

Fig. 4. Stable Time Error, Phase Angle, and Frequency Following a Fault

To answer that, let us examine the same display when the prefault load is increased beyond stable limits as shown in Fig. 5.



Station	Analog	Value
PMCU-1	🟥 TE [ms]	101.80
PMCU-2	🟦 TE [ms]	103.60
PMCU-3	🟩 TE [ms]	101.06
PMCU-4	🟪 TE [ms]	54.38

Station	Phasor	Degrees	Roll Count
PMCU-1	🟥 V1LPM	16.45	0
PMCU-2	🟦 V1LPM	29.12	0
PMCU-3	🟩 V1LPM	6.83	0

Station	Element	Value
PMCU-1	🟥 Frequency	60.232
PMCU-2	🟦 Frequency	59.795
PMCU-3	🟩 Frequency	59.800
PMCU-4	🟪 Frequency	59.428

TXD ○ RXD ● Jul 27 2006 00:49:19 Packets: 629632 Connection: Default Connection TQ: PDC Leap Second: None

Fig. 5. Unstable Time Error, Phase Angle, and Frequency Following a Fault

In the case of a system instability, the phase angles, as shown in the bottom left of Fig. 5, are overlapping, changing, and do not directly convey information that would be useful in making a control decision. Contrast that with the TE shown in the top of Fig. 5. Here we see that the system has separated with the buses connected to PMCUs 1, 2, and 3 and remains synchronized. The bus connected to PMCU 4 is moving off by itself. The slope of trended TE and the instantaneous value of TE provide additional information.

Looking at the event of Fig. 5 when the fault occurred, the TE ramped up as the loss of load caused by the fault raised the frequency. We can confirm this by looking at the frequency in the lower right of Fig. 5. Once the system separated, however, the average frequency at Bus 4 dropped below nominal (60 Hz) and the TE decreased. The TE at Buses 1, 2, and 3 is steady, indicating that there is a load-generation balance. If load is not shed at Bus 4, there will be a frequency collapse at that location.

III. Viewing Time Error Differential

While TE by itself can provide interesting information about the power system, it is by looking at the difference in time error between locations (TED) that we can determine simple, actionable quantities that can be useful for power system control and protection. The following figures illustrate how TED can show system conditions.

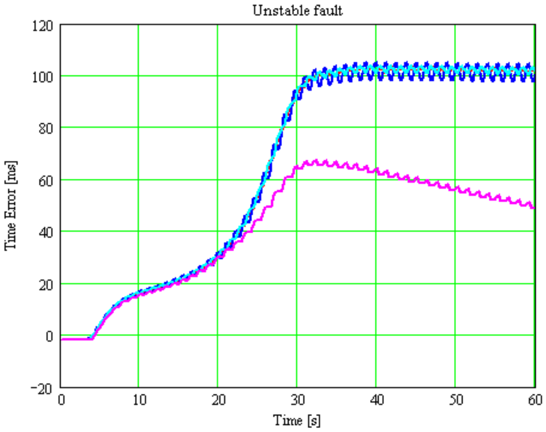


Fig. 6. Time Error at Each Bus

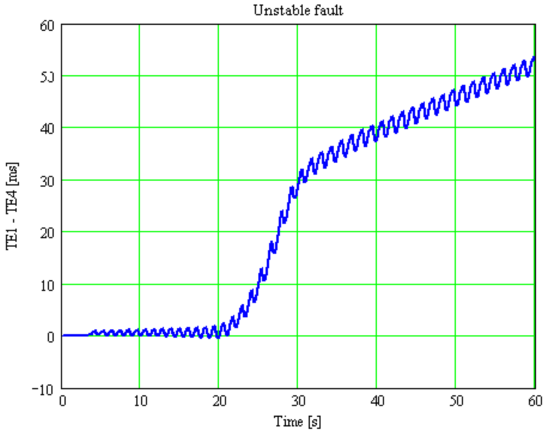


Fig. 7. Time Error Differential (TE1–TE4)

First notice the difference between Fig. 6 and Fig. 7. In Fig. 6, it is not immediately obvious when Bus 4 separates from Buses 1–3. When we look at Fig. 7, it is much more obvious when the separation occurs at just after 20 seconds. This is a case where the TED makes the system condition much clearer than just the TE by itself. The TED can also be used for a definitive identifier of when a system separation takes place.

IV. Stability and Islanding

When a system fault occurs, such as on a power line, the ability to transfer power from one portion of the system to another is diminished. This power transfer characteristic during a fault is shown in Fig. 8.

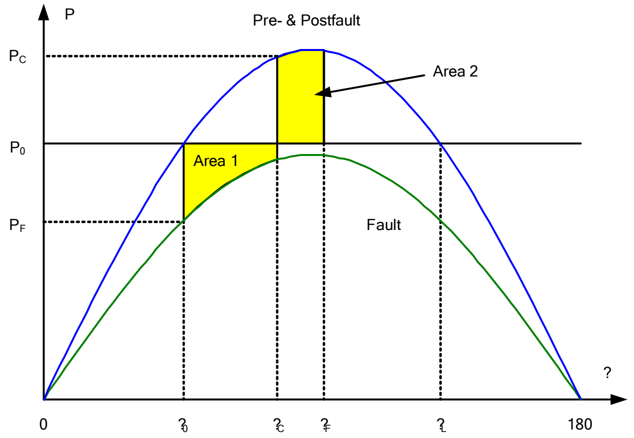


Fig. 8. Clearing Time for Transiently Stable System

In this case, the system will separate, or island, if the available deceleration energy, shown as Area 2, is less than the acceleration energy shown as Area 1. This will happen if the angle between the areas in question goes beyond δ_L. This angle will be somewhere between 90° and 180° or at a TED of between 4.16 and 8.32 ms. Based on this characteristic, we can state that for connected systems, the TED will always be between –8 ms and +8 ms. For disconnected systems, the TED can be anywhere from minus infinity to plus infinity. The value of the TE at a location will be determined by the area-wide generation control and the balance of generation and load.

For the unstable fault on the reference power system of Fig. 9, we can compare the view of phase angle and TED. We used the IEEE C37.118 standard for synchronized phasor measurements to receive and store the phase angle and TE.

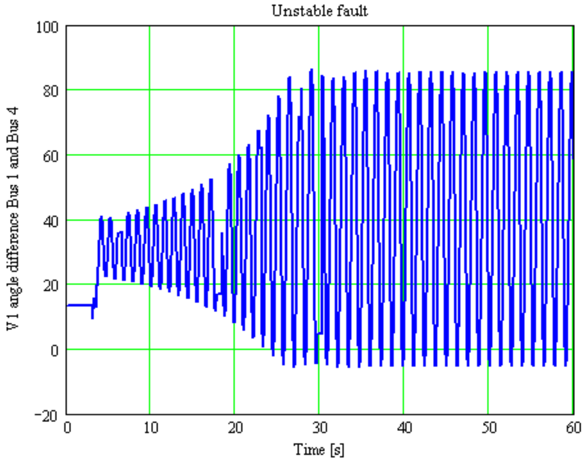


Fig. 9. Positive-Sequence Angle Difference Between Bus 1 and Bus 4

It is not obvious from the phase-angle difference when the system has separated. We can zoom in on the same event's TED (Fig. 7), which yields the graph shown in Fig. 10.

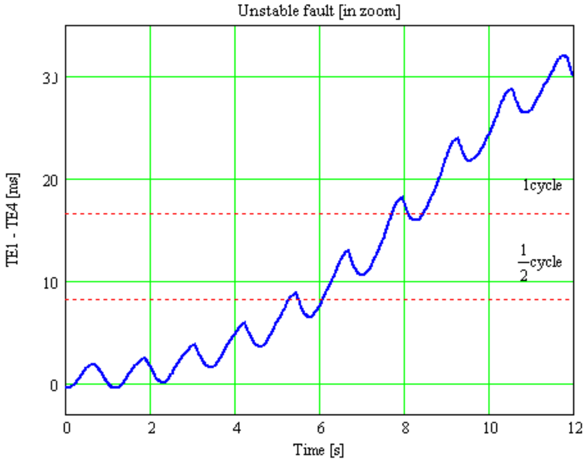


Fig. 10. Detail of TE1–TE4 (Different Time Scale than Fig. 7)

Notice the clarity of the TED curve when compared to the phase angle curve of Fig. 9. This provides an improvement in both visualization-based systems, that is manual control, and automatic systems based on a control from the TED value. We can clearly see when the TED goes above half cycle.

This is also an advantage when communications systems are involved, such as a SCADA-based system. These involve a sampled value. Any sampled value from the phase angles in Fig. 9 is going to be much less stable than that using the TED in Fig. 10.

V. LIMITATIONS OF TIME ERROR DIFFERENTIAL MEASUREMENTS

Recall the definition of TE is the integral of frequency variations. Because integrals continuously accumulate from whatever starting points they use, we need to define a start (and end) time. While the end point of the integral is whenever the measurement is transmitted, the start point needs to be common among all the units involved in the differential comparison. The integration must be restarted or all the TEs set to zero occasionally to eliminate random errors that could accumulate over time. Our tests show that resetting the TE to zero daily or even weekly would be sufficient to eliminate random error accumulation.

Another consideration is that if the voltage at the measurement location goes to zero because of a close-in fault, for example, the TE measurement becomes invalid. For this reason, it is also useful to reset the TE occasionally so that all the measurement units can become valid.

VI. CONCLUSIONS

1. Synchrophasor measurement technology provides useful tools for determining the state of the power system. These tools go beyond voltage, current, and frequency. They add phase angle, time error, and time error differential measurement.
2. No single measurement is best for all conditions. While time error may be useful for islanding detection and unstable swing determination, phase angle measurements may be better for high-speed swing detection.
3. Communications is critical to determining the best visualization and control signal.
4. Studies for the optimal operation and detection points need to be done to avoid premature declaration of stable or unstable conditions.

VII. ACKNOWLEDGEMENT

The authors would like to thank Satish Samineni for assistance in modeling the power system during fault conditions.

VIII. REFERENCES

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IX. BIOGRAPHIES

Roy Moxley received his B.S. in Electrical Engineering from the University of Colorado. He joined Schweitzer Engineering Laboratories in 2000 as market manager for transmission system products. He is now a senior product manager. He has authored and presented numerous papers at protective relay and utility conferences. Prior to joining SEL, he was with General Electric Company as a relay application engineer, transmission and distribution (T&D) field application engineer, and T&D account manager. He is a registered professional engineer in the State of Pennsylvania.

Mirek Wronski received his M.S. in Electrical Engineering from the Technical University of Lodz in Poland. He joined Schweitzer Engineering Laboratories in 2000 as Power Engineer for Substation Equipment Engineering. He is now a Lead Power Engineer in the Research and Development division. Prior to joining SEL, he was with Eskom Company for over 10 years as a Senior Design Engineer. He is a member of IEEE.

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