Sub-Synchronous Grid Conditions:
New Event, New Problem, and New Solutions

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INTRODUCTION

Traditionally, studies are performed to avoid sub-synchronous interactions (SSI) for synchronous generators connected near, or directly with, series compensated lines, HVDC links, or static var compensators. Remedial schemes, different transmission topology, and control systems are used to mitigate or avoid sub-synchronous oscillations (SSO) which can damage a generator.

Wind projects on the other hand, have not typically considered sub-synchronous responses in their models and consequently some utility interconnection studies do not reflect this possibility. Some utilities have interconnection requirements that include statements similar to: “The transmission system in the vicinity of the point of common coupling includes series compensated lines and/or system conditions that may cause sub-synchronous oscillations. The generator is responsible for the studies and protection of their equipment against these conditions which could cause equipment damage.”

The wind energy industry is growing rapidly. More and more utilities are connecting wind generation throughout their system. This includes some generation near series compensated lines, and in some cases, radially connected through series compensated lines.

This paper provides an overview of sub-synchronous interactions, explains a specific sub-synchronous control interaction event, identifies why this interaction is a new problem, and presents solutions for the problem including a new relay application. Although the concepts and applications in this paper directly address wind turbines, the concepts and solutions may be applicable for various SSI.

SUB-SYNCHRONOUS INTERACTIONS (SSI) OVERVIEW

Sub-synchronous events are not new to the industry. [1], [2] They have been studied by many experts and explained in detail in many papers and presentations. One reference explains the various forms of SSI in further detail [3], but the following is an overview of the present terminology.

SSF

Sub-Synchronous Frequency: This refers to the frequency of an oscillation that is less than the nominal frequency (60 Hz in North America) of the power system. This should not be confused with power system fundamental frequency that becomes slightly lower than nominal; (i.e. 57 -59.9 Hz) that may temporarily occur under normal conditions.

Harmonics

Harmonics are frequencies that are multiples of the fundamental frequency (i.e. 2nd - 120Hz, 3rd - 180 Hz for a 60 Hz fundamental).

Sub-Harmonics

Sub-Harmonics are frequencies that are less than the fundamental but at reflections of the harmonics (i.e. 1/2 - 30 Hz, 1/3rd - 20 Hz for a 60 Hz fundamental).

SSI

Sub-Synchronous Interactions: This is a general term that defines two parts of an electric system exchanging energy with each other at one or more of the natural frequencies of the combined system below the fundamental frequency of the system.

SSO

Sub-Synchronous Oscillations: This is a general term that defines the result of SSI described above.

SSR

Sub-Synchronous Resonance: This more specifically defines the known SSR problem of a synchronous generator near a series capacitor when the mechanical mass resonates with the effective impedance of the system. This electrical resonance is known to cause damage in generators [2] and has been studied in depth with many papers written over the last two decades.

SSTI

Sub-Synchronous Tortional Interactions: This more specifically defines the known problem of a synchronous generator near a power electronic controller when the mechanical mass resonates with the negative damping at of the controller at sub-synchronous frequencies. This electrical resonance is known to cause damage in generators [2] and has been studied in depth with many papers written over the last two decades.

IGE

Induction Generator Effect: This more specifically defines the known problem of the electrical properties of the machine resonating with the system at sub-synchronous frequencies. The rotor resistance of the machine presents itself as a negative resistance with respect to sub-synchronous frequencies. The system presents itself as a positive resistance at the system natural frequencies, but if the negative resistance is greater than the positive resistance then sub-synchronous currents will be sustained [7].

SSCI

Sub-Synchronous Control Instability: As stated in a recent presentation [4], this more specifically defines a relatively new problem of "Interactions between a power electronic device (such as an HVDC link, SVC, wind turbine etc…) and a series compensated system."

NEW EVENT

Example Project:

On October 22nd, 2009 two wind generation systems and series compensated system of AEP-Texas in south Texas experienced SSOs. Turbine equipment and utility equipment were damaged during the event [3].

Figure 1 represents the local area near the wind farms.

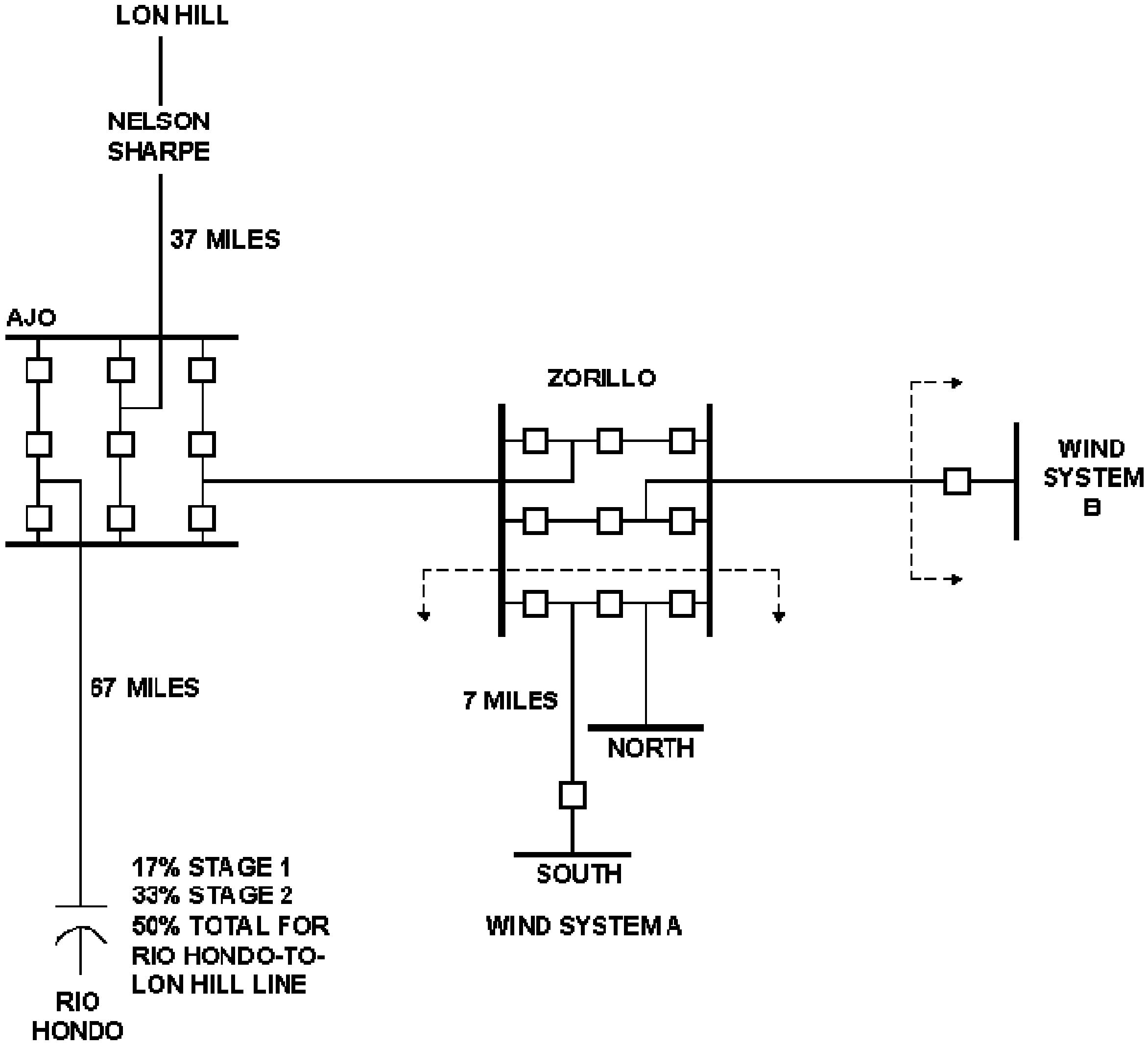


Figure 1: Oneline of the AEP-Texas and Electric Transmission Texas (ETT) System Near Two Wind Generation Systems that Experienced an SSO in October 2009.

On the day of the event at 06:04:44.92 a downed static wire caused a fault on the line between Ajo and Nelson Sharpe. At 06:04:44.97 the fault was cleared by the line breakers (about 2.5 cycle clearing time).

The fault clearing left the Rio Hondo series capacitors in series with the two wind systems.

It is estimated that turbine damage occurred approximately 200 ms after the fault clearing when the turbine equipment exceeded its electrical ratings and system voltages exceeded 1.5 pu (520 kV on a 345kV system). After this, system voltage continued to rise and approached 2 pu with system damage occurring sometime during this condition. Shunt reactors tripped during the event.

The SSO condition was finally damped one and a half seconds after the initial event at 06:04:46.46 when the series capacitor was bypassed.

Figure 2 shows the oscillography that was recorded at the terminals of Wind System A during the event.

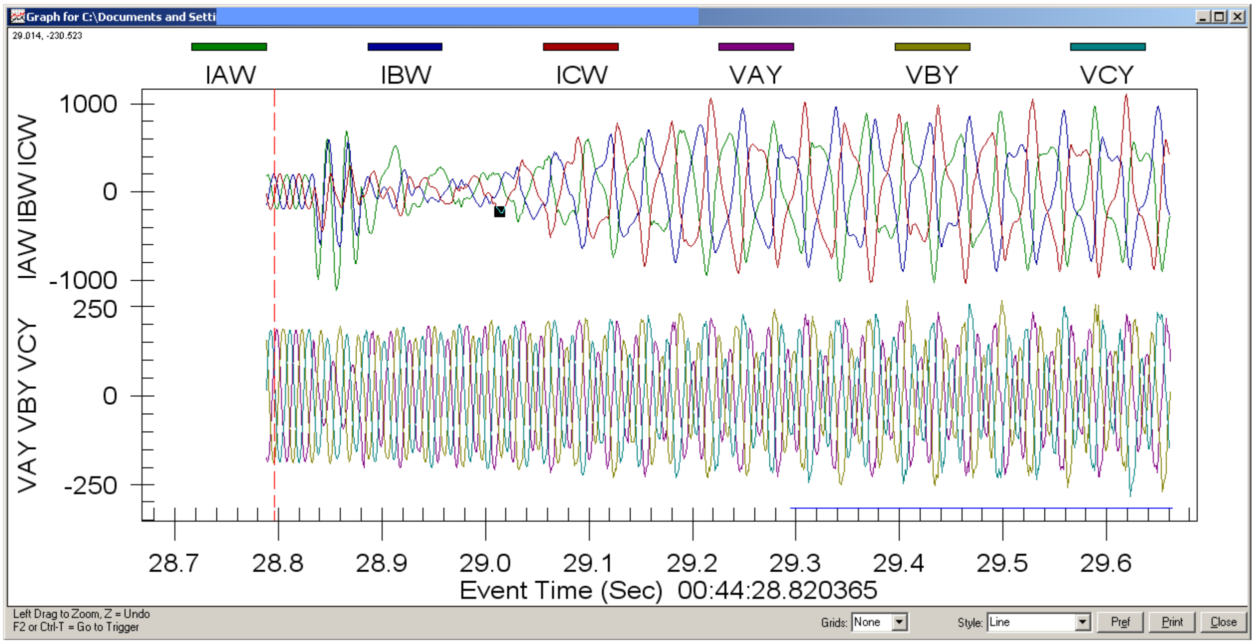


Figure 2: Oscillography Recorded at Wind System A during the Event.

NEW PROBLEM

SSI conditions are not new to the power system, but past studies and events included SSR and SSTI events such as two well known events in 1970 and 1971 [5]. Relays and mitigation focused on the interaction between synchronous machines and series compensated lines. Typical measurement and detection methods used filtered power measurements to identify the SSF conditions. Traditional SSR conditions could result at very low levels of current and would need to be cleared in a matter of seconds.

Because damage occurred within 200 ms of the fault condition, a SSO detection scheme must make a decision in about 100 ms or less.

Figure 3 shows the current of the actual event as well as the sub-synchronous current. The sub-synchronous current magnitude is significant. The SSO event current is mostly sub-synchronous but the fault current exhibits sub-synchronous current as well.

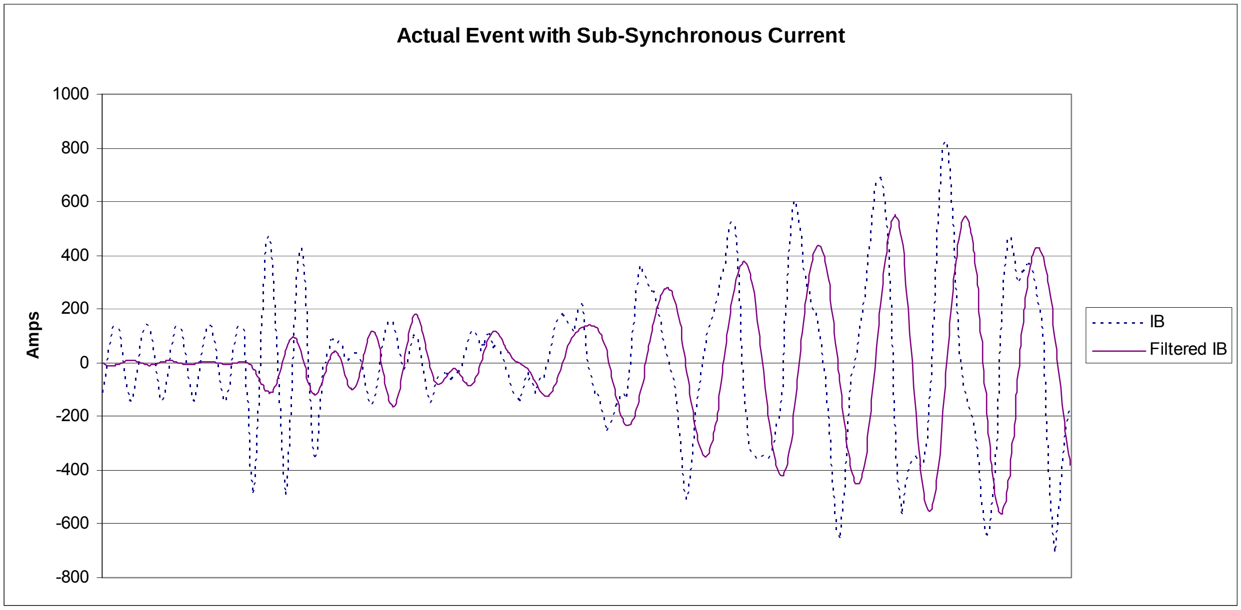


Figure 3: Actual SSCI Event Showing the Faulted Phase Current

Figure 4 shows the voltage of the actual event as well as the sub-synchronous voltage. The sub-synchronous voltage continues to grow regardless of the fault transient.

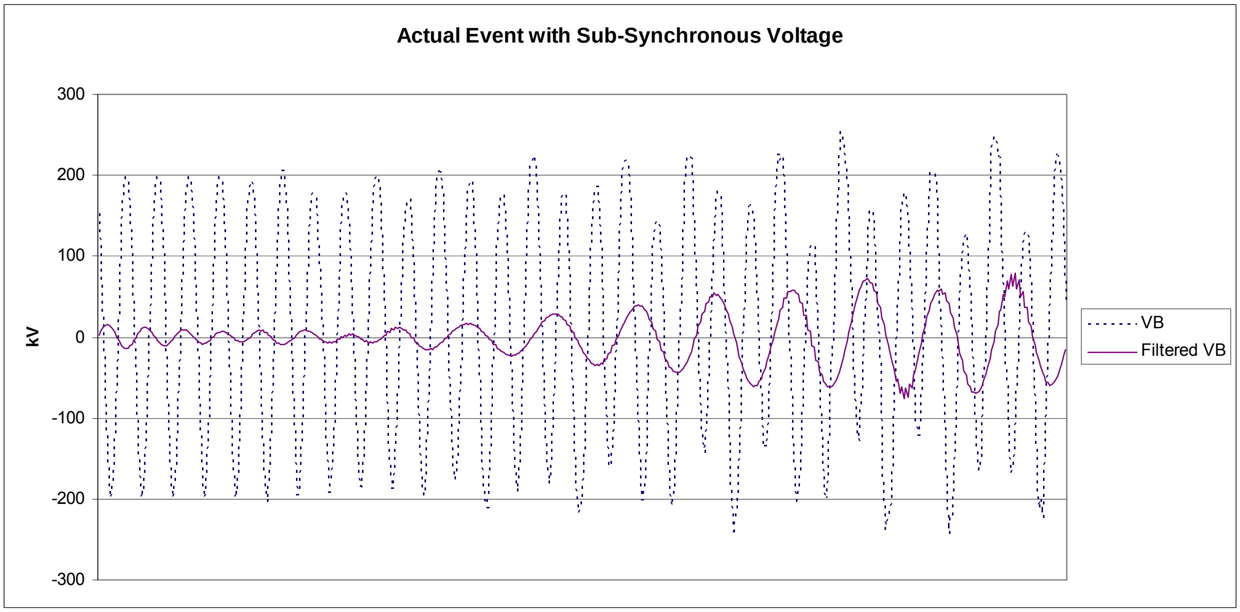


Figure 4: Actual SSCI Event Showing the Faulted Phase Voltage

Figure 5 shows the Power = I_{samp} x V_{samp} of the actual event as well as the sub-synchronous Power. The Power oscillates once the SSO condition begins after the fault is cleared.

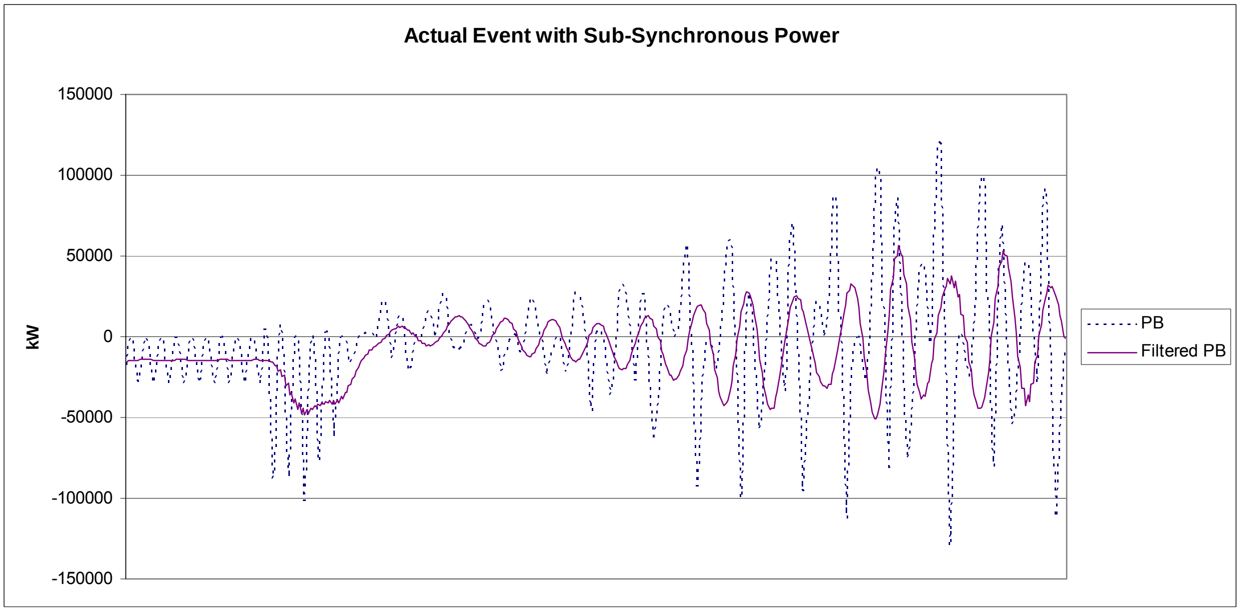
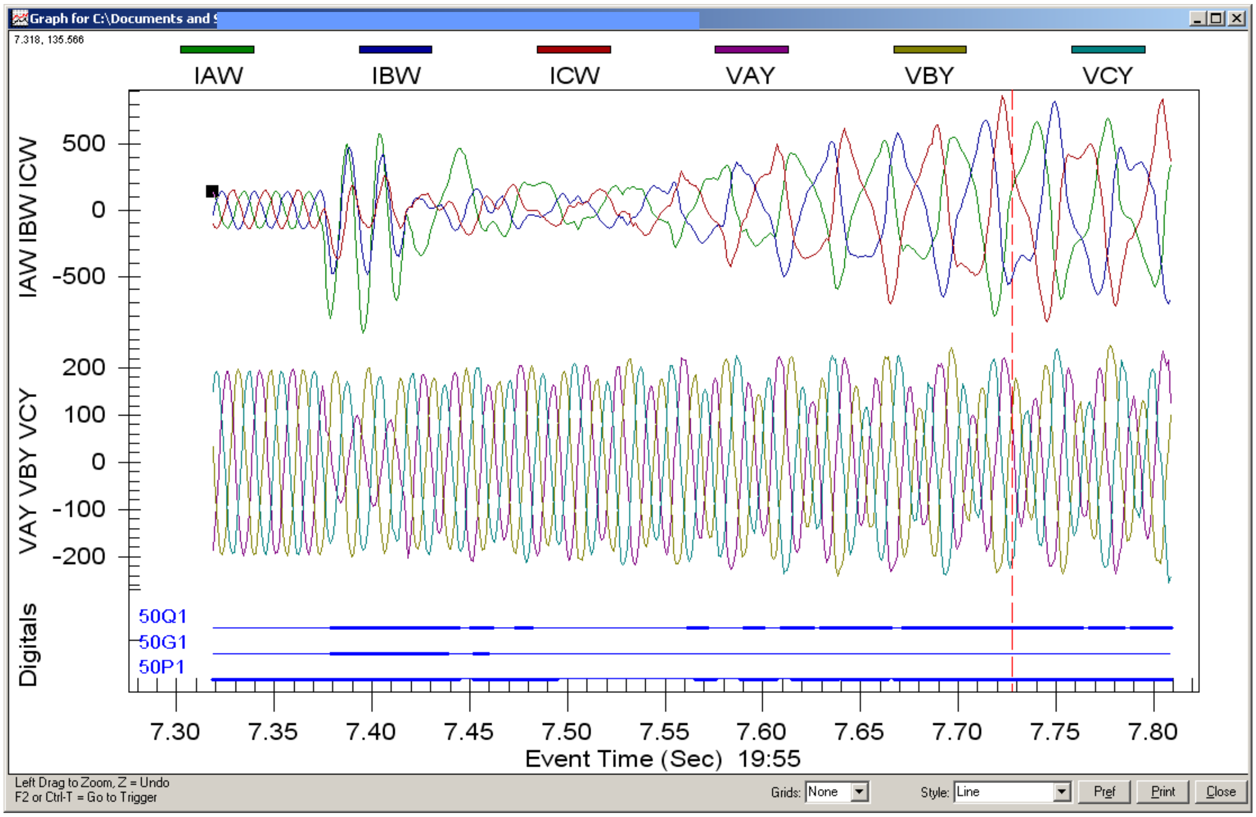


Figure 5: Actual SSCI Event Showing the Faulted Phase Power

The interaction of a wind system and a series compensated system resulted in system conditions that caused damage very quickly. This condition created excessive current at the wind turbine level and at the point of interconnection, and created significant over voltages at the utility level that were not detected by traditional relays.

Figure 6 shows the actual event played back through a relay with traditional low set overcurrent elements.



Grids: None

Style: Line

Figure 6: Actual SSCI Event Showing the Response of a Traditional Over-Current Relay

The overcurrent elements (50P1, 50G1, and 50Q1) were all set at 0.25 A (60 A primary). The phase and negative sequence elements picked up and dropped out and the ground element did not pickup at all during the sub-synchronous event.

The event presents itself as caused by IGE. The rapidly increasing current at sub-synchronous frequencies is also the result of IGE. However, very recent studies have shown that this problem presents itself over a wide range of slip frequencies and is negatively damped by the doubly-fed induction machine control systems [9].

The interaction between the series compensated line and the wind system was not the traditional mechanical interaction with the turbine or the traditional induction generator effect (IGE). It is an interaction with the control system of the turbine. Therefore, the new problem is labeled Sub-Synchronous Control Instability (SSCI) [4].

Although there is ongoing research, it is believed [3] that the Doubly-Fed Induction Generators (DFIG) are the most susceptible to SSCI and both Wind Systems A and B had DFIGs.

Series Compensation

Series compensation in transmission systems is a very common solution where there is a need to transfer power over long distances. Series compensation has been used widely since 1950 [5]. For those that may be unfamiliar with the concept, the series capacitance electrically shortens the line by having the capacitance in series with the inductance of the line. More and more utilities are using this technology and more lines require series compensation to support higher levels of power transfer.

Transmission Expansion

There are several transmission expansion projects going on throughout the US, but to realize that this new SSCI problem is not a localized possibility, the following projects are highlighted. Many more throughout the US are presented in the February 2010 "Transmission Projects: At A Glance" [6].

In Texas, the Competitive Renewable Energy Zone (CREZ) transmission projects over 800 miles of lines) will allow a 200% increase in renewable interconnections. This will include many 345 kV series compensated lines.

Last year Pacificorp began construction on a ten or more year plan to add 2,000 miles of transmission across the west. This Energy Gateway project will include 500kV lines, series capacitors, and SVCs. This effort is largely due to the renewable energy projects in the interconnection queue which totals more than 10,000 MW.

NEW SOLUTION

After the event several parties, including the utility, analyzed what happened to determine what could have been done to prevent it. In addition to many other questions, the question was raised "Is there a relay that could detect this?" Several relay manufacturers were consulted and the response from the application engineers and in some cases the R&D departments was "No, there's no existing relay on the market that could detect this condition."

After one party proposed a custom analog system for the solution it was determined that additional consideration should be given to a microprocessor based solution. A microprocessor based solution would have greater flexibility and data recording options. Since microprocessor based relays have built in Fourier and cosine filters it was believed that the necessary sub-synchronous quantities would not exist. Some manufacturers make measured analog quantities available for use in user logic, but the values were still post-filter. However, the cosine filter does not completely filter the sub-synchronous quantities. Figure 7 shows the final filter response of one manufacturer's relay.

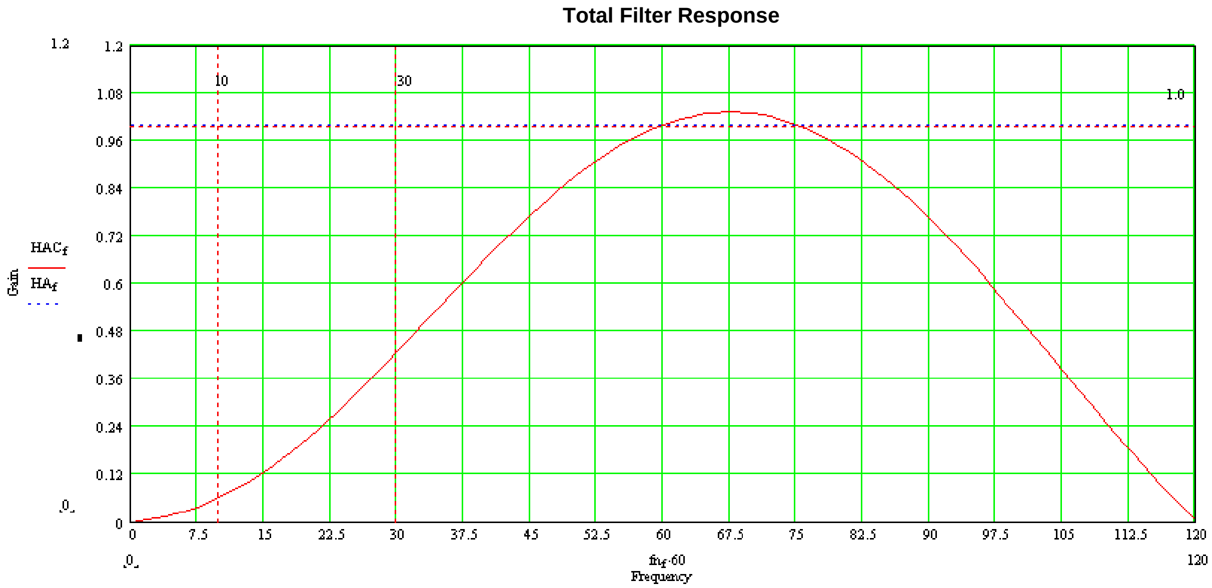


Figure 7: Total Filter Response of Analog Values Available for User Logic

With this understanding, further discussion continued and a relay algorithm was developed to detect Sub-Synchronous Frequencies (SSF).

A Solution or Not?

So that we could better understand the need for protection, a parallel is drawn to a more common protection system. Frequency relays are commonly applied on the power system to protect equipment or to make system changes to alleviate the abnormal frequency. In contrast to SSFs these off-nominal frequencies are in the range of 57 to 62 Hz for a 60 Hz system, but the application philosophies are similar.

Utility scale generators usually have control systems to maintain nominal frequency and they have frequency protection to trip the unit if frequency approaches or exceeds the machine's capability. Multiple frequency thresholds and time delays constitute a typical frequency detection scheme.

At the generator point of interconnection, most utilities or Independent System Operators require frequency protection in addition to the generator frequency protection. As with the generator relays, these relays must be coordinated with the operating practices of the grid.

At the grid level there are systems and operating practices to maintain nominal frequency on the grid. Load shedding schemes and other mitigation schemes are often driven by frequency relays and utility generators are controlled to maintain system frequency.

These three levels of protection and control are implemented for nominal frequency protection. The same philosophy should be applied to SSF conditions:

- Turbine level SSF control and SSCI protection
- Interconnection level SSF backup protection
- Utility level SSF control and protection

So to answer this section’s title question: “Yes, this new algorithm is one part of a complete SSF control and protection solution.”

At the utility level remedial action was considered as well as phasor measurement across the grid. Neither of these solutions was desirable on their own as they required communication systems that would need to be duplicated for redundancy, but again, a communication system may be part of the overall system solution.

The Algorithm

Figure 8 shows the block diagram of the algorithm. The solution is unique in that it is using custom user logic to create a digital filter, and then uses custom user logic to create the relay algorithm to decide when to trip.

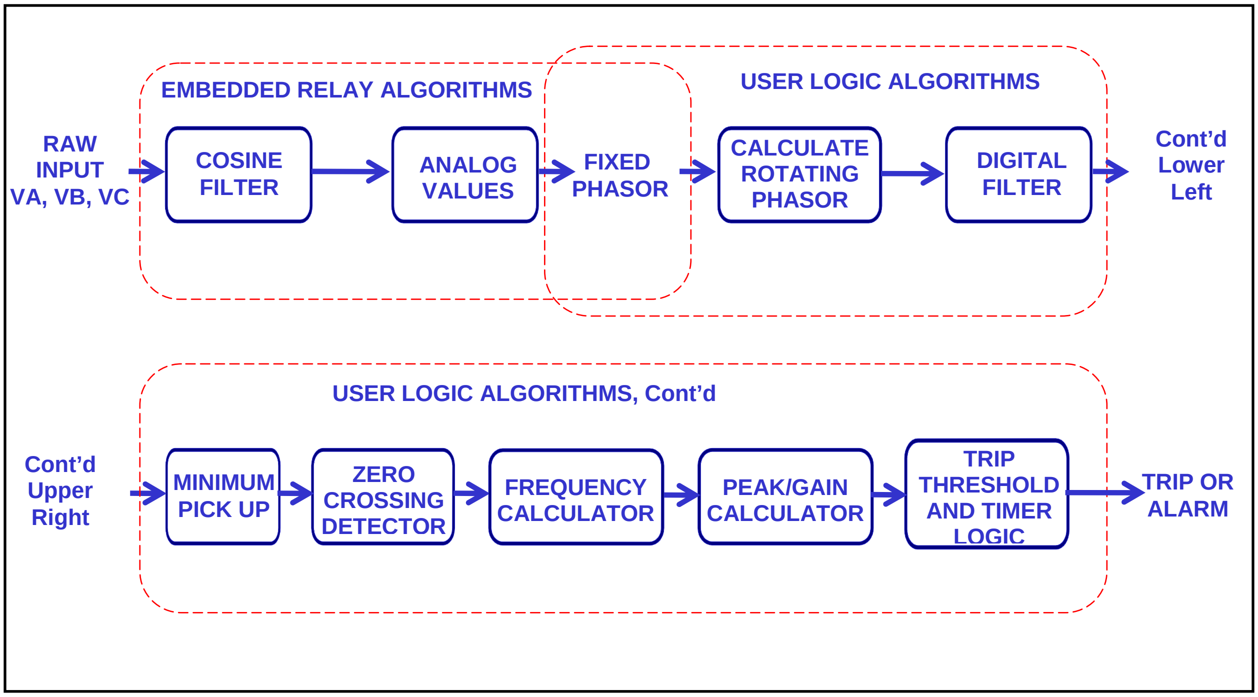


Figure 8: SSF Relay Algorithm Block Diagram

Raw Input Voltages

The voltages were selected as the measured values. Initially the algorithm considered current, but as the complete algorithm developed and the system was tested using actual non-SSF events, security was compromised when using current inputs. Power inputs were also considered, but because of the limitations of logic, power was not used. If an embedded solution is ever developed, the manufacturer should consider using power as an input into the algorithm.

Cosine Filter

The selected relay applies a low pass filter and an embedded cosine filter to the raw measured voltages. In general, this filtering attenuates signals less than or greater than 60 Hz by design. It removes power system harmonics, but the sub-synchronous quantities are attenuated. Figure 7 shows the attenuation at certain frequencies. The magnitude may be gained based on the Figure 7 if a specific frequency is desired.

Analog Values

The three voltages are obtained as fixed phasor magnitudes. The voltage quantities used are VAFIM, VBFIM, and VCFIM. These represent the A, B, and C phase fundamental (cosine filtered) instantaneous magnitudes. The relay produces these quantities assuming it is tracking the power system frequency. For a steady state 60 Hz input signal or for a off nominal signal where the relay is tracking the frequency, these magnitudes will be constant. However, since we will be using the relay in a fixed sampling mode (no frequency tracking) when an off nominal frequency waveform is applied, the output of the fixed phasor is a sinusoid. The apparent frequency is the difference between the applied frequency and 60 Hz.

Calculate Rotating Phasor

In order to use the logic based digital filter, the algorithm needs samples of a rotating phasor. It takes the angle of the voltages and rotates it 45 degrees based on the fixed sample rate of 8 samples per cycle. This reconstitutes the input signal.

Logic Based Digital Filter

The reconstituted waveform is sampled by a logic based Infinite Impulse Response (IIR) filter. Figure 9 shows the block diagram of the IIR Filter. With the relay's processing rate fixed at 8 samples per 60 Hz cycle, the user logic may be used to develop a digital filter. The IIR filter implemented has a cutoff of 50 Hz. The filter specifications could be changed for specific applications, but this filter met the initial criteria for speed and accuracy.

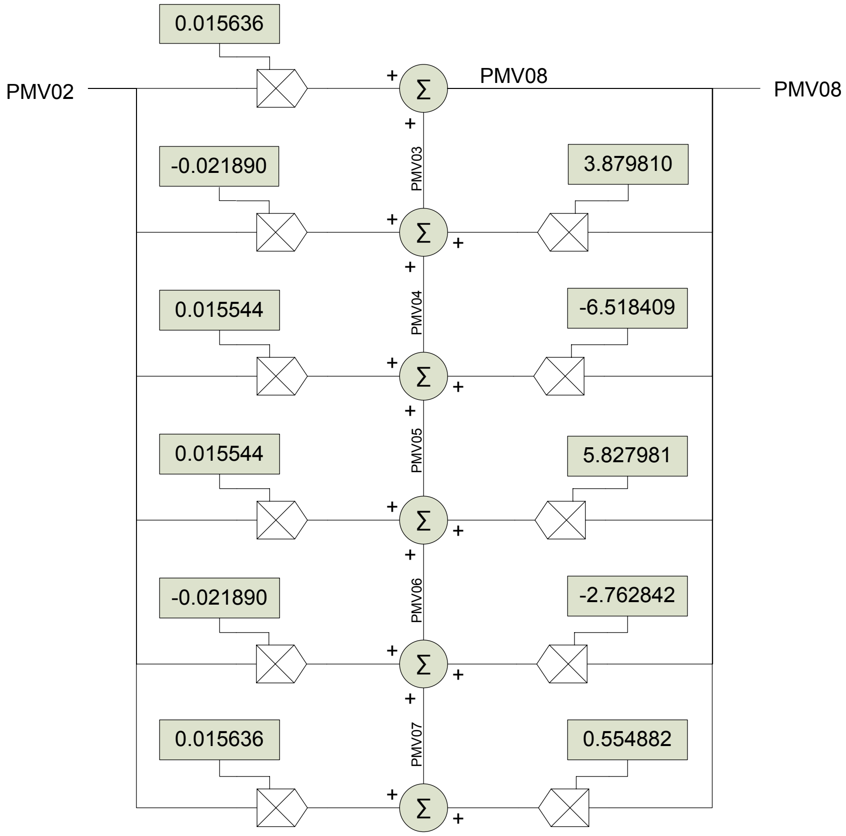


Figure 9: Logic Based Digital IIR Filter Block Diagram

Minimum Pickup

Much like an overcurrent relay or an impedance based relay, the algorithm has a user settable minimum pickup. This could be used to ride through known transient conditions. For example, if there is a system condition such as capacitor switching that causes transient overvoltages in the vicinity of the subject system, then a higher minimum pickup may be needed to avoid tripping on these acceptable conditions. As with any protection scheme their may be compromises between security and sensitivity. The minimum pickup element is checked on a per phase basis.

Zero Crossing Detector

Once the waveform is above the minimum pickup, the zero-crossing detector is applied to the output waveform of the digital filter. This detector establishes timing information that is used by the frequency and threshold logic. The detector is designed to monitor as low as 5 Hz.

Frequency Calculator

The frequency calculator is applied to all three phases. During testing it was determined that a single phase frequency measurement could result in over- or under-tripping. The frequency calculator is accurate to within 0.1 Hz for a steady state signal and operates across the range of 5 to 48 Hz.

Peak/Gain Calculator

The peak of the waveform is determined. The time required to determine a peak depends on the lowest frequency that the algorithm is needed to detect. For example, a 10 Hz waveform takes 100 ms for a complete cycle.

Within the same calculations, the filter output may be gained at or below specifc frequencies. For this application, 30 Hz was selected so that any frequency measured at or below 30 Hz has a 1.4 gain factor. This is the inverse of the attenuation of the relay's embedded filter at 30 Hz. The output of this part of the algorithm is a magnitude and it has acceptable sub-synchronous detection down to 8 Hz. Lower than 8 Hz and the relay's transformers begin distorting the input signal.

Threshold and Trip Timer Logic

The user may select multiple peak output comparator values with independent timers. Because of the nature of the SSF conditions and the short time before damage, the thresholds were set at 0.01 pu of nominal voltage with a time delay of 8 cycles and 0.1 pu of nominal voltage with a time delay of 6 cycles.

The programmable logic allows the user to trip or alarm via an output contact, relay-to-relay logic, and/or trigger events.

Performance

As with any protection scheme there is a balance between security and sensitivity. Many tests were performed on the algorithm, but two are highlighted here. The first, shown in Figure 10 is the performance of the algorithm on the actual event. Sub synchronous oscillations start at approximately 11.79 and the relay asserted the TRIP element at 11.96, 170 ms after the oscillations started.

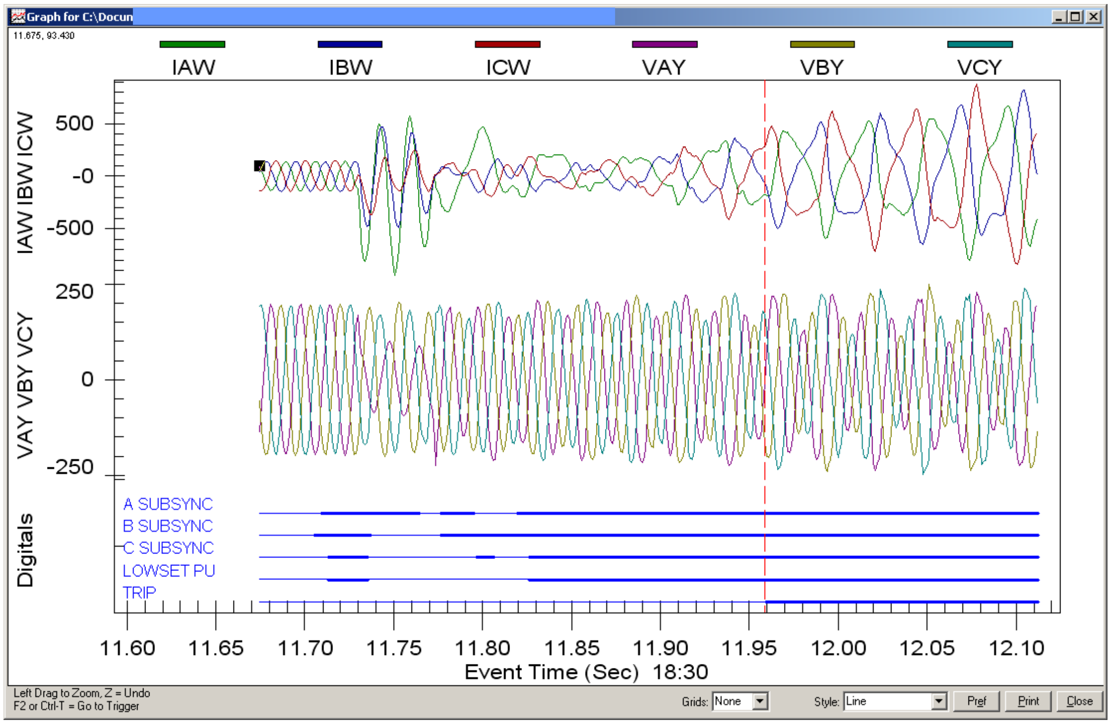


Figure 10: Algorithm Response to the Actual Event

To verify the algorithm's security, several 500 kV single and three pole events were applied to the relay. Figure 11 shows the algorithm response to a single phase bus fault on a 500kV system that caused overtripping concern with a current based SSF scheme. The graph shows 345 kV voltage levels as the event was normalized to be played back through the test relay with settings for 345 kV.

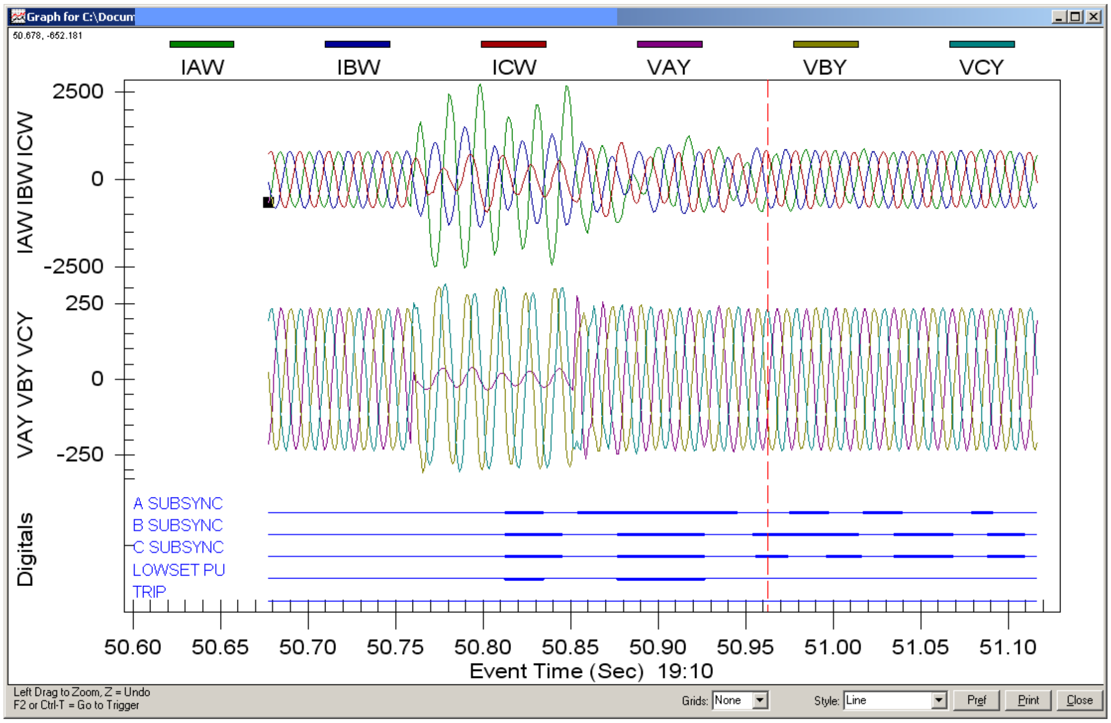


Figure 11: Algorithm Response to an EHV Single Phase Bus Fault

APPLICATION

In May of 2010, microprocessor based relays implementing the algorithm were applied by AEPSC (as the service provider to ETT) in two locations as backup protection to the generator. The generator is responsible for mitigating the SSI with their control system and responsible for a protection system that would trip the turbines to avoid damage from SSFs. The relay and algorithm were commissioned with sub-synchronous frequency tests and standard trip tests. At the time of writing this paper no known events have occurred since installation.

ADDED VALUE OF THE MICROPROCESSOR BASED SOLUTION

This event occurred in October of 2009 and a solution was ready in January of 2010. It took only two calendar months to develop a solution using a microprocessor based relay. This solution was able to benefit from the vast earlier research, but without a user programmable relay the solution could not have been implemented, tested, and applied so quickly and with such flexibility for changes.

The microprocessor based solution may be modified without changing out analog components and if added embedded features are made available in new firmware by the manufacturer a simple upgrade will likely be available.

The data recording is flexible and easily changed if needed. The data recorded may be played back into a relay for further testing and research as desired.

LIMITATIONS OF LOGIC BASED SOLUTIONS

One limitation of logic based solutions is the amount of logic available in the relay. This solution utilized nearly all of the protection logic available in the relay.

When working with new concepts and solutions that the relay was not originally designed to do, care must be taken to test and validate aspects of the relay that might normally go untested for a typical application. For example, the current transformers of the relay produced a cleaner waveform at frequencies less than 10 Hz than the voltage transformers.

When using logic the user must understand the input sources used. The reconstituting of the waveform in this application is one example that required specific knowledge of how the relay internal code worked in order to properly adjust the input signal.

CONCLUSIONS

1. Turbine manufacturers must design control systems that avoid or mitigate SSO.
2. Turbine manufacturers must protect their systems from damaging SSO conditions.
3. Interconnection facilities at the point of interconnection should install backup protection using an SSF detection system or comparable technology.
4. Utilities and/or Area Operators should include interconnection study requirements and control system specifications that address SSCI for all turbines on transmission systems that may now, or in the future, have series compensation.
5. Utilities and/or Area Operators should communicate with generators possibly impacted by series compensated lines and determine what is necessary to mitigate and/or detect SSIs.
6. Logic devices can minimize the development of special protection or detection schemes, but care must be taken when using a relay for something outside of its original target application.

FOR FUTURE CONSIDERATION

1. Relay manufacturers should develop an embedded SSF detection solution that may be applied at the local level without communication across the grid.
2. Further relay developments should investigate power measurements as well as oscillation measurements instead of or in addition to magnitude measurements.
3. Interconnection projects can have added protection by installing an SSF detection device at the point of interconnection.
4. A method by which a utility could validate a turbine control system for SSCI needs to be developed.

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AEP

AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined.

AEP-Texas is the utility operation of AEP in Texas.

ETT is a joint venture of AEP and Mid-America Energy Holdings.

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Garth Irwin graduated from the University of Manitoba Hydro. At the Manitoba HVDC Research Centre he performed many studies for projects including sub-synchronous resonance. As Vice-President at Electranix he is studying the specific SSCI and assisting utilities and turbine manufacturers for control solutions.

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