ELECTRIC POWER
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# Torsional Interaction Between Electrical Network Phenomena and Turbine-Generator Shafts

## Plant Vulnerability

*Technical Report*

# Torsional Interaction Between Electrical Network Phenomena and Turbine-Generator Shafts

Plant Vulnerability

**1013460**

Final Report, November 2006

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This report describes research sponsored by the Electric Power Research Institute (EPRI).

The report is a corporate document that should be cited in the literature in the following manner:

*Torsional Interaction Between Electrical Network Phenomena and Turbine-Generator Shafts: Plant Vulnerability.* EPRI, Palo Alto, CA: 2006. 1013460.

# REPORT SUMMARY

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The report documents the results of a literature review, surveys, and detailed sensitivity analysis (using a generic system model with real turbine-generator shaft models) to document the interaction between electrical network disturbances and torsional modes of turbine-generators. The key challenge is that much of this interaction depends on the actual torsional modal response of the unit and the endurance limit of the shaft material.

**Background**
To study the effects of grid disturbances on turbine-generators requires gathering and sharing event data between transmission system planners, operators, and power plant staff. In today's deregulated environment, this has become a more difficult task. The torsional behavior of steam turbine-generators is explained in EPRI report 1011679. This report examines grid events that can cause torsional fatigue in turbine-generator shafts and low-pressure turbine blades.

**Objectives**
To identify the zone of vulnerability of large steam-turbine generating units to torsional interactions due to network switching phenomena and other devices on the transmission system.

**Approach**
The team performed three tasks. A literature review was conducted to identify all the various sources of torsional interaction phenomena. This review—together with an historic account of events that have been reported to result in damage to turbine-generator shafts in the literature—has been documented here. The second task was to conduct a survey, followed by phone interviews, of large steam turbine-generator owners in the United States to learn if they had recently experienced events that they believe may have led to severe torsional interactions. This also is documented. Finally, a generic power system model was developed and into it incorporated a model of two real turbine-generators (one 1800-rpm and one 3600-rpm unit). Using this model, the team performed a sensitivity analysis related to network switching phenomena (based on the literature search and phone interviews) to identify key factors that influence torsional interaction between the network and the turbine-generator shaft. The goal was to identify the zone of vulnerability for the study units and, hence, determine what general lessons may be learned from this process.

**Results**
The study has formalized a systematic approach for identifying the zone of vulnerability of a power plant to the potential of damaging torsional interactions. The approach is based on comparing the peak transient torques observed for various network faults and disturbances to the peak transient torque for a machine terminal fault. In addition, the report provided significant

insight into the various factors that influence the level of torsional interaction and how to assess when detailed torsional interaction studies are necessary.

### EPRI Perspective

EPRI's involvement in monitoring, material testing, and root cause analysis of torsional vibration issues and incidents goes back to the early 1980s. This report complements the tutorial report 1011679 and provides qualitative risk assessment of 1800/3600-rpm steam-turbine and generator torsional interaction with the electrical network.

### Keywords

Torsional vibration
Torsional interaction

# ACKNOWLEDGMENTS

The authors of this report would like to gratefully acknowledge and thank the following individuals for providing technical input and guidance to this project:

Isidor Kerszenbaum, Russell Chetwynd—Southern California Edison

Tom Wait—Pacific Gas & Electric

Robert Tomala, Tony Khalid—Exelon

Bajarang Agrawal—Arizona Public Service

Bob Bjune—South Texas Project

Ian Grant, James Hovious, Robby Bottom—Tennessee Valley Authority

Rob Dayley—Entergy

Matt Hober—Pennsylvania Power & Light

The authors wish to also gratefully acknowledge the assistance of Melanie Myers in both proof reading the document and helping to format the document.

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# 1 INTRODUCTION

## 1.1 Background

There are continuing reports of mechanical damage to steam turbine blades and turbine-generator shaft systems attributed to interactions between the turbine-generator and the electric network, in the USA and abroad[1-1]. There are also reports of "unusual noise" in the turbine-generator related to large amplitude transient disturbances in the electric network. These included system faults, transmission line switching actions and probable bypass and re-insertion of series capacitor banks. In one nuclear plant, the plant operators do not even have to call the system operator to know when automatic reclosing[1-2] has taken place on the grid: they can feel it though the loud boom and abrupt jolt in the turbine-generator which accompanies the automatic line reclosing. In addition, presentations at a recent EPRI conference described some of more recent publicly acknowledged incidents as well as some of the historical studies and general understanding of the factors that may make a plant susceptible to interactions.

To study the effects of grid disturbances on turbine-generators requires the gathering and sharing/correlating of event data between transmission system planners, operators and the power plant staff. EPRI has found that such exchange of important information is more prevalent outside the USA at utilities that are still vertically integrated. In the USA, de-regulation of the electric power business has reduced access to such information by the different parties. This has made it more difficult for the plants to obtain records of disturbances in the network and perform analyses to correlate plant information with network events. Although there were a number of studies reported in the literature during the 1970s and 1980s, there are no recent reports of simulation studies that describe stress levels for transient events or provide guidelines for system design and operation to minimize possible damage.

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[1-1] Turbine-generator torsional natural frequencies have very low damping. When faults and switching actions excite oscillations at these frequencies, they will persist for many seconds. Hence, this may cause components to experience many damaging fatigue cycles before the mechanical oscillations decay below fatigue limits.

[1-2] Autoreclosing is the action of restoring transmission lines to service subsequent to automatic tripping of their associated circuit breakers due to electrical faults. Experience indicates that many faults on the bulk power overhead transmission system are temporary, and hence by reclosing them there is a high probability that the fault may have already been removed, or burned up. In the absence of autoreclosing, longer duration outages could be experienced unnecessarily. Successful autoreclosing can enhance the stability and overall system reliability, and hence is widely used. However, autoreclosing into a permanent fault may adversely affect system stability, hence due consideration must be given to this aspect of any application.

The torsional behavior of steam turbine-generators is explained in the EPRI report 1011679 [1]. This report examines the grid events that can cause torsional fatigue in the turbine generators shafts and low pressure turbine blades.

## 1.2 Zone of Vulnerability (ZoV) for Torsional Interaction

Typically, there are specific attributes of a turbine generator and its surrounding transmission network that increase the risk for torsional damage.

Torsional interaction phenomena fall into three main categories:

1. Interactions with system transient disturbances, including faults, reclosing etc[1-3].
2. Subsynchronous resonance (SSR) interactions.
3. Device Dependent Subsynchronous Oscillation (DDSO)

All of these interactions are dependent on characteristics of the design of the turbine generator as well as the transmission system, although the dependency varies with the phenomenon.

While there are guidelines and analysis procedures for many of the interactions between turbine-generator shaft systems and transmission networks they require detailed analysis. There is a need for the plant to assess, without detailed studies, the risk of interaction with the network. The concept of a Zone of Vulnerability (ZoV) for torsional interaction was developed by EPRI for this purpose. The EPRI concept is that there may be an area near the power plant where these transients may damage the turbine-generator shaft system. This area is called a Zone of Vulnerability (ZoV). The ZoV may have specific geographical boundaries or depending on the practices within the network may involve some switching on isolated lines or portions of the system as depicted in Figure 1-1. The definition of the ZoV may include such variable conditions as:

- Number of units in operation at the station
- Number of transmission lines in service
- System loading level
- Transmission system loading pattern
- Type and location of system disturbance

[1-3] This includes the torsional interactions near twice system frequency (120 Hz in 60 Hz systems, and 100 Hz in 50 Hz systems).

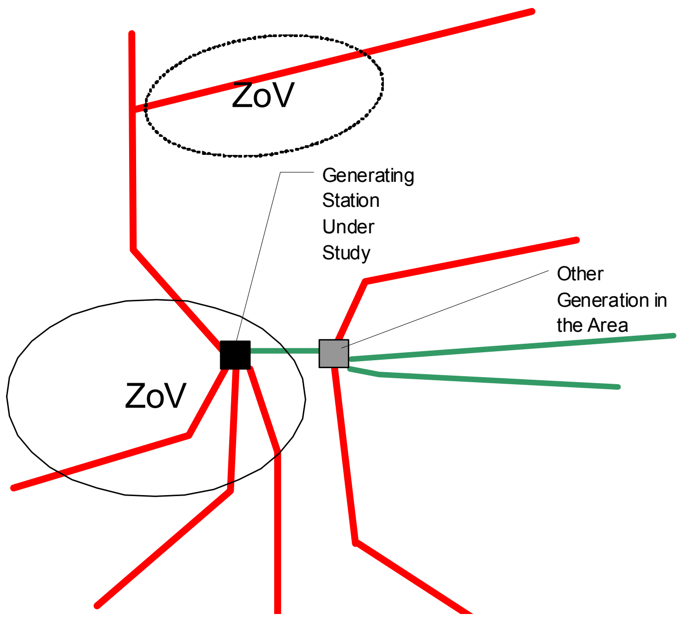



**Figure 1-1**
**Zone of Venerability Concept**

## 1.3 Automatic Reclosing of Transmission Lines

An important subset of system torsional interactions with turbine-generators is automatic reclosing (also often abbreviated as autoreclosing). Reclosing into a fault (unsuccessful reclosure) can be much more severe than applying two faults (separated considerably in time) at the same location. If the line recloses after a few cycles, the fault torque is repeated and shaft oscillation may be amplified. A doubling of stress amplitude may result in an order of magnitude increase in fatigue life expenditure, due to the fact that fatigue and life expenditures are very nonlinear with amount of stress applied. This effect has been largely responsible for the concerns with high-speed reclosing; that is, reclosing a transmission line in a matter of a fraction of a second.

## 1.4 Use of the ZoV

The ZoV concept provides guidelines for plant owners to be able to estimate the region of the electrical network within which electrical phenomena can cause potentially damaging stress on the turbine-generator shaft. Thus, if autoreclosing, series capacitors, large power electronic equipment or other electrical network related devices or phenomena are within the ZoV of a plant, site specific analytical studies, monitoring and testing may be required to quantify the risk. Such detailed studies would then afford the opportunity for plant engineers to more accurately set protection strategies/settings for the generator and turbine, and more effectively work/coordinate with the transmission provider to mitigate such vulnerabilities. Also, the ZoV region may be used by the generating station and transmission personnel to take appropriate precautions during transmission system maintenance to minimize the adverse impact of faults on the safe operation of station.

## 1.5 Objectives

The objectives of this project are:

- Catalogue transient grid disturbances that have been known to have caused (historical) torsional interaction concerns
- Develop a simplified model to depict possible torsional interaction concerns
- Through sensitivity analysis on the simplified model identify the system parameters that affect the ZoV

## 1.6 Report Layout

The layout of the remainder of this report is as follows:

- Section 2 provides a general description of the types of torsional interaction phenomena by describing the exact mechanism of the phenomena.
- Section 3 contains a detailed listing of historic accounts of torsional interactions between turbine-generators and electrical network phenomena.
- Section 4 is the core of the report. It provides the results of the sensitivity analysis performed using the simplified system model and thus presents insight into the parameters that influence the zone of vulnerability of a power plant to torsional interactions. This section is complemented by Appendices C and D, which provided more detail on how the ZoV for a plant may be determined for interactions with series capacitors and large power electronic devices such as high-voltage dc converters.
- Section 5 summarizes the results of the study as well as providing recommendations for how to assess when disturbances or network events might require detailed studies for a given power plant.
- Section 6 provides a brief discussion on suggested future work.
- The Appendices of the report provide some additional information, such as the details of the simplified system model used for the analysis in Section 4, information on the interviews and literature search conducted during the study, and a self assessment guide

# 2
# GENERAL DESCRIPTION OF THE PHENOMENON

The phrase torsional interaction has been used [1] to refer in general to all phenomena related to interactions between the electrical power system and turbine-generator torsional mechanical modes of oscillation. These phenomena can then be further split into three main categories:

1. General Torsional Interaction due to network switching and other events (e.g. faults, line switching, load rejection etc.)
2. Subsynchronous Resonance (SSR)
3. Device Dependent Subsynchronous Oscillation (DDSO)

Each of these categories will be discussed below in some further detail. However, first some brief background discussion on turbine-generator shaft dynamics is pertinent.

## 2.1 Turbine-Generator Torsional Shaft Dynamics

The shaft of any turbine-generator may be represented by a finite-element model. For manufacturer design purposes this is often the type of detailed modeling that is employed today in the industry. Finite-element analysis (FEA) is based on taking the object under study (in this case the entire turbine-generator drive train) and representing it by a geometrical model consisting of a large number of linked discrete regions—that is, finite elements on a grid. In the case of a large steam turbine-generator, these discrete regions may be for example each rotor blade stage. Equations of equilibrium, based on the basic physics of rotational dynamics, are written for each of these elements and thus a system of differential equations is constructed. As with any mechanical system, the system will have N-1 modes of natural vibration/oscillation. Here N designates the number of linked (or coupled[2-1]) elements (or masses). Thus, if our shaft model consists of a hundred coupled masses (e.g. representing every rotor disk-wheel and shaft segment etc.), then we would expect to compute ninety-nine modes of torsional (twisting) oscillation between various shaft segments.

Figure 2-1 depicts an illustration of a steam-turbine generator shaft. In this example a FEA model of the shaft may represent each disk in the four turbine stages (HP, IP, LP1 and LP2) and all other shaft segments as individual elements/masses. However, an analysis of such a model will typically identify modes of torsional oscillation that are associated primarily with oscillations between the turbines and the generator mass. This is because the stiffness between

[2-1] The word coupled here is used in a general sense meaning a physical connection between two elements (masses) on the rotating shaft, as opposed to a manufactured "coupling" that is located where two rotor segments meet in the mid-standard of a shaft.

adjacent disks within a turbine stage is much greater than the stiffness of the longer shaft segments that connect the turbines (and generator) together. Thus, typically for the purposes of studies related to torsional interaction one can reduce the rather complex FEA model down to a lumped mass-spring model that represents each turbine as a single mass connected together by spring constants representing the effective stiffness of the shaft segments. So in the case of our example in Figure 2-1 we would end up with a five-mass spring model such as shown in Figure 2-2. Of course the lumped spring-mass model must be detailed enough to capture the modes of interest for torsional interaction studies with the electrical network.

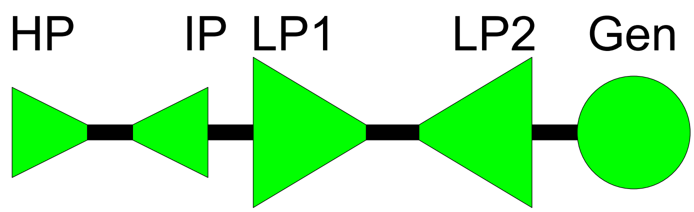



**Figure 2-1**
**Diagrammatic representation of a typical large steam-turbine generator shaft. The turbines here are assumed to be single-flow.**

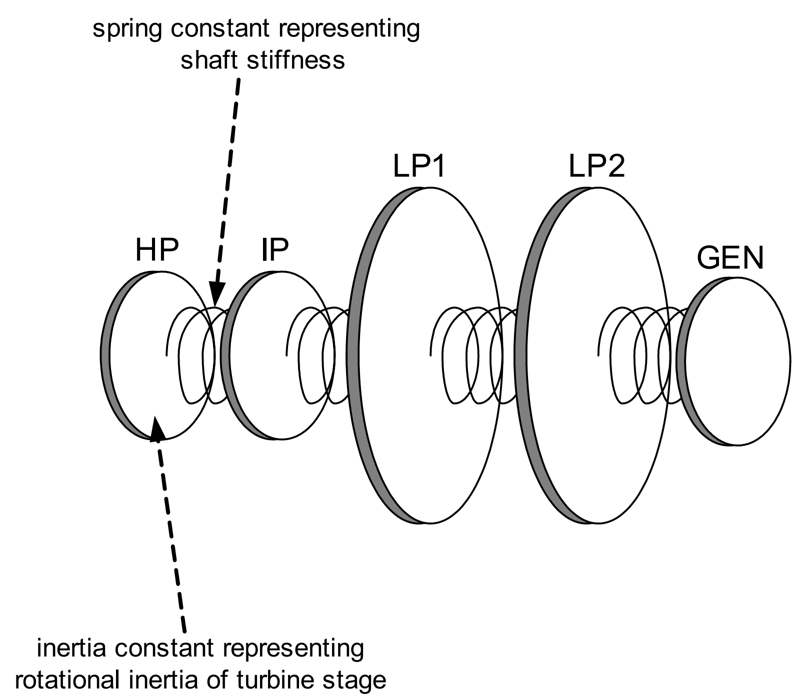



**Figure 2-2**
**Lumped Mass-Spring Model of Turbine-Generator Shaft**

So for the above example since there are five lumped masses there will be four modes of oscillations among the masses and a common stationary mode for the entire system. When this mechanical system (the turbine-generator shaft model) is connected to the electrical power system model the common mode becomes an electromechanical mode of rotor oscillation with the electromagnetic forces forming the spring constant. Since the effective electromagnetic stiffness between the generator and the electric power system is much weaker than the mechanical stiffness among the masses on the turbine-generator shaft, the entire shaft essentially oscillates in unison for this common electromagnetic mode of rotor oscillation

As an example, let us consider the turbine-shaft model of the IEEE First Benchmark for SSR analysis [4]—this represents the actual shaft of the original Navajo turbine-generator in Arizona. This shaft is modeled by six masses the high-pressure (HP) turbine, intermediate-pressure (IP) turbine, two separate low-pressure turbines (LP1 and LP2), the generator mass and a rotating exciter. This is shown in Figure 2-3. Calculating the modes of this system, five torsional frequencies are identified: 47.5, 32.3, 25.6, 15.7 and 20.2 Hz. Furthermore, by plotting the normalized eigenvectors of theses modes the so-called mode shapes can be illustrated [2], [3] (see Figure 2-3). What the mode shapes indicate is the relative motion of each mass for the given mode. For example, for the 20.2 Hz mode we see that the relative angular motion of all masses except for the exciter is roughly zero. This indicates that for this mode mainly the exciter mass is in motion and it is oscillating torsionally against the rest of the turbine-generator shaft.

Thus a mechanical model can be developed and incorporated into the power system electrical model for the purposes of torsional interaction studies that analyze the stress on the connecting shaft segments. The model parameters are in the form of polar moment of inertia constants for each mass and spring constant for each shaft segment (see Appendix A). Two other comments are pertinent with respect to the mechanically shaft model:

1. The torsional modal frequencies, are determined by the mechanical characteristics of the turbine-generator shaft and thus remain constant provided the mechanical components remain unchanged i.e. there are no changes made to the turbine-generator shaft such as replacing the generator rotor or turbine blades etc.
2. The modal damping associated with the torsional frequencies is hard to predict and can best be determined through tests [5]. However, it can be assumed that the modal damping is typically low, particularly for the lower frequency subsynchronous modes. Furthermore, damping tends to increase with increasing steam mass flow and increasing modal frequency. Therefore, for investigating transient torque phenomena (such as discussed in Section 2.4) damping may be neglected as it is low enough to have little impact on the first few cycles of transient torque.

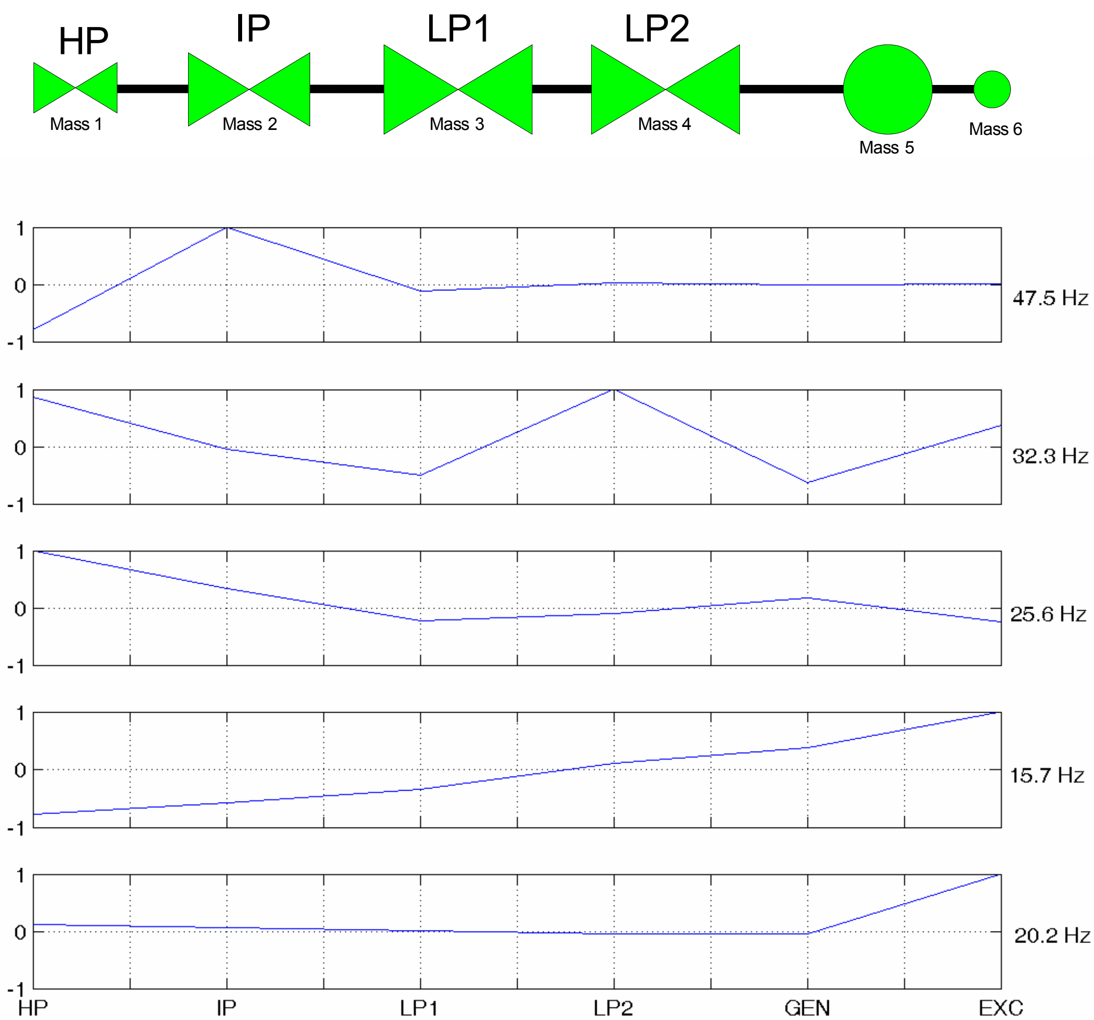



**Figure 2-3**
**Model and Torsional Modes of the IEEE First Benchmark Machine (3600-RPM machine).**

## 2.2 Subsynchronous Resonance

This phenomenon is perhaps the most widely recognized and studied of the type of torsional interaction [2], [6]. This phenomenon was fist observed at the Mohave Generating Station in Southern Nevada in the 1970's [7], where it resulted in damage to the generator shaft on two occasions. In this case the phenomenon is one resulting from a resonant condition. In essence a resonance between a torsional mode of the turbine-generator shaft and a natural frequency of the electrical transmission system existed that destabilized the torsional mode. To illustrate this consider the simple case shown in Figure 2-4. For this simple case the electrical network has a resonant frequency as fn given by:

$$f_n = f_o \sqrt{\frac{X_C}{X_L}}$$ **Eq. 2-1**

where XL is the total network reactance including the transmission line reactance, the generator step-up transformer reactance, the generator subtransient reactance and the equivalent reactance of the rest of the system. XC is the series capacitor reactance. Since the series capacitor reactance is a percentage of the transmission line reactance, the resonant frequency fn is always less than the nominal system frequency fo. Hence the phenomenon is called subsynchronous resonance. Now let us assume a perturbation occurs in the electrical network. This would clearly excite the torsional modes on the mechanical shaft of the turbine-generator. Thus, the speed perturbations on the turbine-generator shaft at a torsional mechanical frequency of say fm will result in inducing two side bands frequencies of (fo – fm) and (fo + fm) on the stator current. If the condition fn = (fo – fm) is met, then we have a pure resonance between the electrical and mechanical system which is the condition of subsynchronous resonance (SSR). In Appendix C, greater detail on how screening analysis can be performed to identify the risk of SSR and what proven mitigation strategies can be employed is presented.

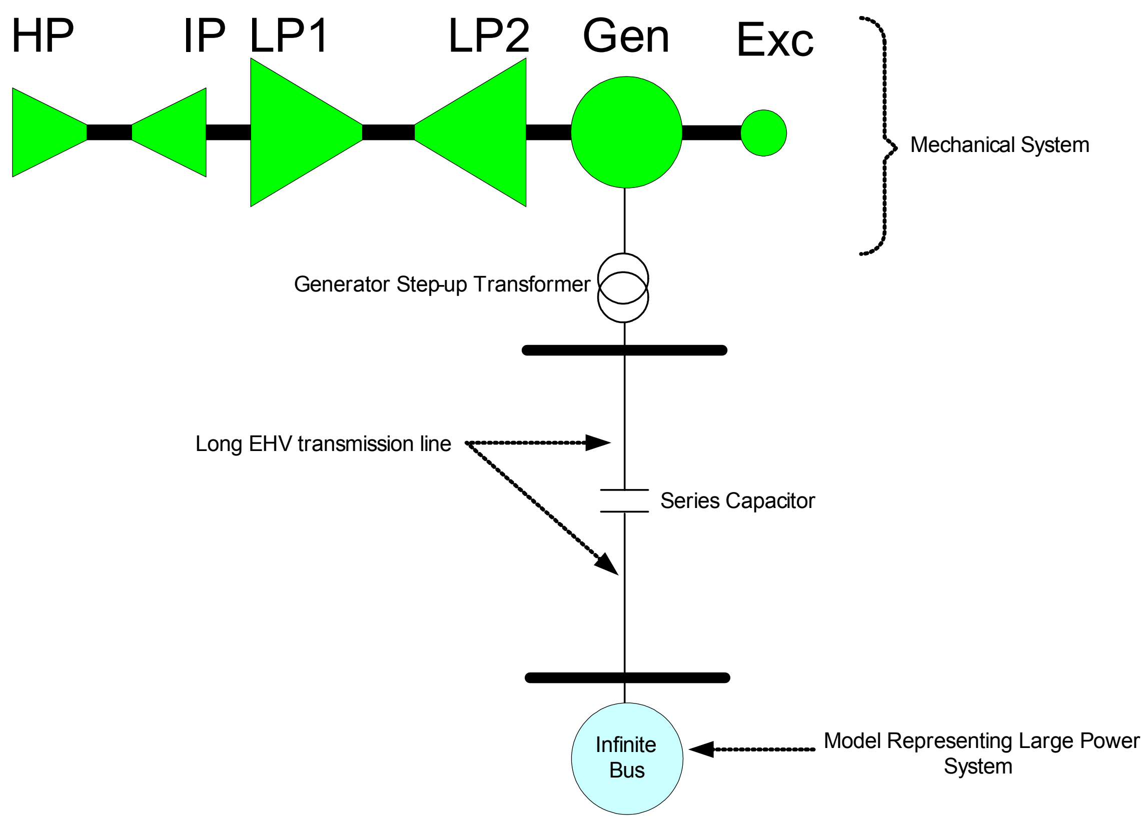



**Figure 2-4**
**Simple System Model for SSR**

## 2.3 Device Dependent Subsynchronous Oscillations

Torsional interaction can also occur as a consequence of fast acting control loops on large power electronic devices such as high-voltage dc (HVDC) converter stations or on turbine-generators themselves. This phenomenon is due to control interactions and is not a resonance phenomenon. Thus the solution is in proper tuning of the controls and or introduction of filtering and supplemental damping controls.

Torsional mode destabilization due to the action of a power system stabilizer (PSS) was first observed in 1969 on Ontario Hydro's Lambton unit [15]. Similarly, in 1985, torsional interaction between a turbine-governor and the turbine-generator shaft was reported in Canada [16]. In both cases, the problem was due to the use of mechanically-derived speed signals in the feedback control system. The speed signals were taken off of the turbine-generator shaft at points where oscillations of the affected torsional mode(s) was highly observable. As an example, the PSS was found to have an unfavorable frequency response characteristic around the torsional modes of concern thus resulting in positive feedback that destabilized the mode. The solution was to use notch filters to remove the torsional frequencies from the stabilizing (speed measurement) signal. Most modern controllers, such as PSS, will used signals such as integral of accelerating power (which inherently has lower torsional content) and will also incorporate notch and low-pass filters to avoid torsional interaction.

Another type of device dependent subsynchronous oscillation (DDSO) is that which occurs between turbine-generators and the controls of large power electronic devices on the transmission system. This phenomenon is often more commonly referred to in the literature as subsynchronous torsional interaction (SSTI). SSTI was first encountered and mitigated at Square Butte in 1980 [10].

Figure 2-5 helps to explain the phenomenon. Consider a sizeable HVDC converter station in the vicinity of a large steam-turbine power plant. The HVDC rectifier station will have fast acting controls that act to regulate dc power and/or dc current on the HVDC system. Now consider a small perturbation in the speed of the turbine-generator. This would result in a perturbation in the generator power, and voltage. This then translates into a change in the ac bus voltage at the nearby HVDC terminal, assumed here to be rectifying. The ac bus voltage perturbation would affect the dc voltage, current, and power. The HVDC control, however, would quickly react to restore the dc current. This reaction is reflected in the generator current electrical torque. The time constants and control variables in the HVDC control system determine both the gain and phase relationship between the initial speed perturbation and the subsequent electrical torque perturbation. This may have a negative damping (destabilizing) effect on one or more of the torsional modes of the turbine-generator. In Appendix D a discussion is provided on how screening analysis may be performed to identify the potential for such interaction and the well proven methods for detailed analysis and mitigation of the phenomenon.

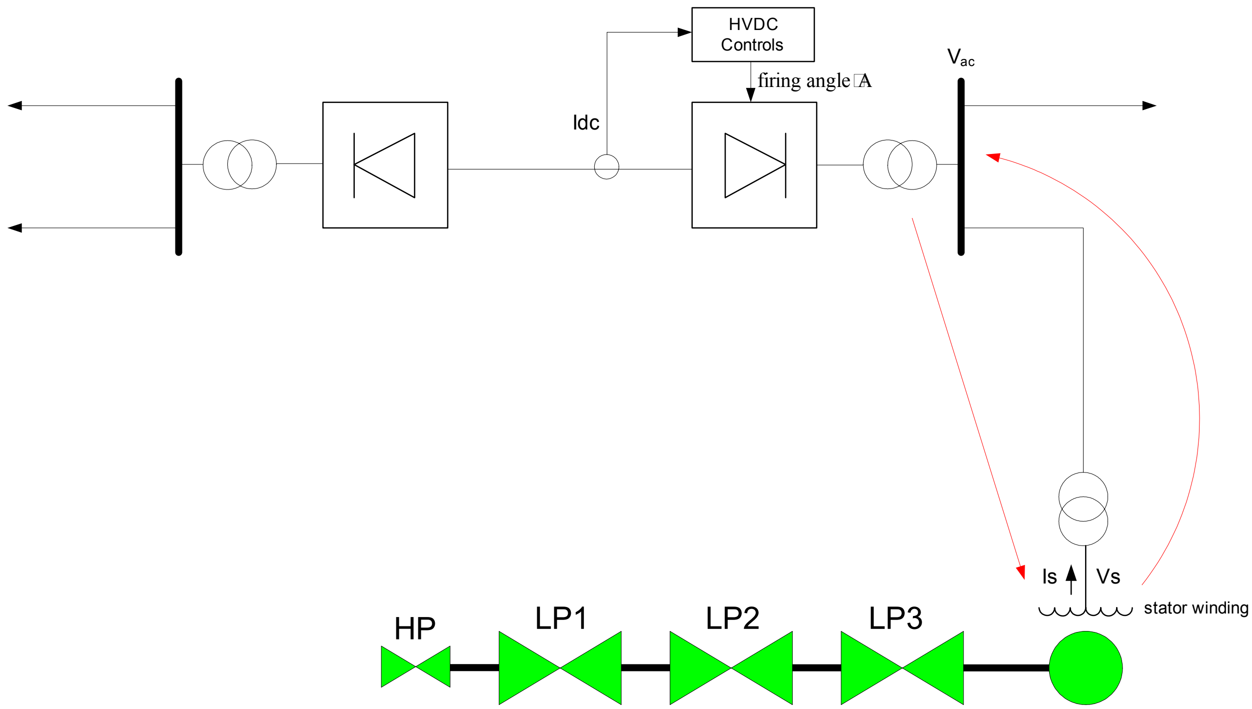



**Figure 2-5**
**Subsynchronous Torsional Interaction with HVDC**

DDSO can also be caused by shunt power electronic devices such as static Var compensators (SVC) or static compensators (STATCOM) [11], [12]. An interesting note, however, is that in the case of SVCs, STATCOMs and voltage source HVDC systems, the impact of the device may in fact be positive (i.e. result in increased torsional damping) rather than detrimental [13], [14]. A clear example of this is the use of SVCs for torsional damping as a means of mitigating SSR (this is presently exercised at plants in the Western US grid such as Springerville in Arizona).

Large variable speed drives used inside the plant also employ power electronics that may be a source of DDSO, if large enough in comparison to the unit (see UIF calculation in Appendix D).

The key observation here is that torsional interaction caused by control interaction is a negative damping torque phenomenon. That is, the actions of a fast control loop on the electrical system can result in a component of torque, of electromagnetic origin, at the generator which is at a frequency and phase relationship such as to degrade or totally eliminate the inherent mechanical damping of a mechanical torsional mode of oscillation. The solution is in tuning and or supplementing the control scheme in order to mitigate such negative damping impact.

## 2.4 Torsional Interaction Due to Faults, Network Switching and Other Events

Apart from resonance phenomena and control interactions, many of the regular switching events within a power system can result in detrimental torsional oscillations. These include:

1. Circuit breaker operations that switch transmission lines, generators, transformers or other devices in or out of service (including load rejection).
2. Transient fault and fault clearing operations in the network.
3. Automatic high-speed reclosing (HSR) of transmission lines (whether successful or unsuccessful) [17] - [23].
4. Out-of-phase synchronization of the turbine-generator [24], [25],
5. Cyclical or pulsating loads such as arc furnaces or particle accelerators, and
6. Insertion/switching of series capacitors.

In all these cases, the electrical transient (i.e. rapid fluctuation in electrical power due to a disturbance) leads to a response of the turbine-generator mechanical shaft system due to the changes in electromechanical forces. The torsional response is met by low mechanical damping of shaft angular displacements. Like a step function, these transients will excite all the natural modes of the turbine-generator shaft. The larger the initial stimulus (the initial transient) the higher the impact on the turbine-generator, with a relative independence on the natural modes of the specific turbine-generator (with the exception of those close to twice the power frequency). This is a major difference between this type of torsional interaction, and SSR, where the latter is manifested by a resonance phenomenon (as described earlier and in the Appendix C).

In the case of a fault on a transmission line the initial occurrence of the fault and subsequent tripping of the line produces two large electrical torque steps on the generator. This sets the mechanical system into vibration and excites the torsional modes on the turbine-generator shaft. Depending on the severity and vicinity of the fault, the transient torque response on the turbine-generator shaft can peak at 2 pu or more. If high-speed reclosing is exercised, then a second step is experienced by the turbine-generator (whether the reclosing is successful or not) within a short span of time before the torsional oscillations have fully subsided. Thus, it is conceivable that the second event could occur in such a relationship to the first such as to further exacerbate the transient torques on the turbine. These phenomena are examined in detail later in this report (Sections 4.5 to 4.7).

The impact of an electrical system transient on a turbine-generator shaft is normally quantified in terms of expenditure of shaft fatigue life per incident. While most switching events will only cause negligible amounts of fatigue usage, fatigue life usage in excess of 1% may result from load rejection, faults (e.g. three-phase faults) on generator terminals, synchronization out-of-phase, unsuccessful re-closing and single pole (phase) reclosing. In addition, shaft fatigue is cumulative. Therefore the fatigue life expenditure in a shaft system is a culmination of all past events (over the lifetime of the shaft system) that produced strain oscillations above the endurance limit of the shaft material. When the cumulative fatigue life expenditure exceeds a certain threshold, a surface fatigue crack will be initiated at the point of highest stress concentration.

# 3
# CATALOG OF HISTORICAL TORSIONAL INTERACTION EVENTS

## 3.1 Summary of Survey and Interviews

One of the objectives of this project was to perform a survey, followed-up by phone interviews, to catalogue recent transient grid disturbances that may have caused torsional interaction concerns. A general survey document was developed and distributed electronically to utility and generating plant personnel to obtain additional disturbance specific information.

This survey was distributed to approximately 110 individuals. Responses were received from seven nuclear plants. Most of them only discussed one event and there was no indication that the events had resulted in more than a change in vibration on the turbine generators. Table 3-1 lists the events described.

Based on these responses and other known torsional events, the project team scheduled telephone interviews with plant personnel to further understand the nature of the torsional disturbances. These interviews are summarized in detail in Appendix B.

Both the written responses and telephone interviews showed that known torsional stress resulting from system faults or switching actions is a rare event. Most of the utilities reported that there was little indication of most of the system disturbances inside the plant. Specific damage resulting from these disturbances was usually limited to a need to rebalance some portion of the machine. The number of incidents where the units were subjected to large amplitude transient events seemed to also be quite low. It is important to note that torsional concerns may have been higher than the reported experience of the plant because some of the plants had changed ownership and there was little monitoring or incident recording.

Having digital fault recorders in power plants with the ability to quickly extract and post process information following a disturbance would significantly help the ability of plant staff to assess and correlate the impact of system events on the turbine-generator shaft.

**Table 3-1**
**System Events Near Nuclear Plants Reported in the EPRI Survey conducted during this study.**

| Plant number | Event Description | Effect on Turbine Generator |
|---|---|---|
| 1 | The initiating event was an undetected open phase on the GIS 400-kV bus section link that as a result of switching during auxiliary transformer commissioning caused circulation of high zero sequence current that initiated back-up earthfault protection operation that tripped three 400-kV transmission lines, two 400-kV/132-kV transformers and the turbine generator. One of two units at the plant was on line and supplying 97% of its rated power at the time of the trip. | No torsional information recorded. |
| 1 | Faults on two 765-kV transmission lines led to a transient instability causing out-of-step relays to operate resulting in a separation and successful islanding of a portion of the transmission system including the plant. The deficit of power in the islanded area caused the frequency to drop from 50 Hz to 47.72 Hz and activated all stages of the underfrequency load shedding scheme. Approximately 40% of the load in the islanded area was shed. The frequency of the islanded system then increased to 51 Hz and quickly stabilized at 50.65 Hz. | The plant maintained full power throughout this transient and there was no observed change in operation. |
| 1 | One unit experienced an emergency shutdown of the nuclear reactor from full load. This was correctly followed by an automatic trip of the turbine. The generator should have automatically disconnected from the grid but the reverse power protection and automatic voltage regulator failed to perform as expected and the generator remained connected to the grid but did not maintain synchronism. The out-of-step condition was detected by system protection and the unit was tripped. | There was no reported damage to the unit from this event. |
| 2 | An underfrequency event occurred in the 500-kV grid because of the loss of several lines (345 and 500 kV) importing power into the system. The frequency dropped from 60 to 58 Hz for 30 sec. One unit at the plant tripped due to the underfrequency relay. The other unit remained in operation. | The unit that tripped showed high vibration on the generator lead box. Cracks were later found in a bushing and in the lead box. |
| 3 | Unit routinely experiences voltage perturbations due to line switching or relaying. A voltage regulator problem resulted in a large power oscillation (greater than 200 MW) that lasted several minutes before action was taken to stop the oscillation. | No reported noise in the plant or damage to the turbine generator. |
| 4 | Loss of a transformer from a nearby generation facility resulted in a large upswing in generator output VARs. No other observed effect. | No reported noise in the plant or damage to the turbine generator. |
| 5 | A direct lightning strike on the unit 2 main power transformer resulted in a plant trip. However, this was not associated with a grid disturbance but plant equipment degradation. | No reported noise in the plant or damage to the turbine generator. |
| 6 | A lightning stroke to a 500-kV tower ~ 40 miles from the plant. It created a 3-phase fault at that location. | Event created oscillations in the rotor shaft that triggered the overspeed detection that tripped the unit. |
| 6 | A 3-phase fault at a nearby 500-kV substation (grounds left on buswork). | Event created oscillations in the rotor shaft that triggered the overspeed detection that tripped the unit. |
| 7 | Significant transient swings were observed on the generator voltage, current, and excitation output metering. Investigation showed a neighboring utility with a HVDC line inverter substation was switching in or out capacitor banks. It is not understood why the plant reacted the way it did for a routine switching event. | There were no protective trips of any of the three units at the plant and no reported damage. |

## 3.2 Historical Context of Torsional Interactions

The project team conducted a literature review (over one-hundred technical papers, a representative selection are included in the reference list) to identify system events and technical analyses that resulted in significant torque disturbances.

Concerns that transmission line switching, fault clearing and line re-closing practices may result in damage to the turbine generator shaft systems was the subject of a number of studies and technical papers in the 1970's. These papers discuss detailed studies to identify transmission system characteristics, fault locations and fault types that were of concern. A number of the references are representative of the results obtained during this period [17], [19], [20], [36], [37], and [38].

These papers showed some agreement on the magnitudes of shaft torque for each type of fault or switching action. The IEEE Working Group report [39] is a good summary of all the information in the other papers referenced. It discusses all the factors then known to amplify shaft torque levels including timing of breaker operations, strength of the network after the fault is cleared, number of machines and lines sharing fault current, etc. The common consensus on automatic high speed re-closing (HSR) of lines is that critically timed unsuccessful high-speed re-closing of multiphase faults could yield torsional oscillations leading to significant fatigue life expenditure, significant changes in vibration of the machine, slipping and galling of couplings and/or gross shaft yielding. This reference reinforces the statements in other papers that planned switching events (line switching, etc) that do not result in a sudden (transient) change in average power on a generator greater than 50% of its rated power, should not cause shaft fatigue concerns.

These papers do not agree on the amount of fatigue damage that might result from a system fault. One technical paper [41] and two EPRI reports [43], [44] discussed methods to estimate fatigue damage based on a count of the number of cycles of torque oscillation experienced at critical shaft locations. The potential damage for each cycle was based on the amplitude of the cycle, the mean shaft torque during the cycle and stress concentrations due to shaft geometry or previous incidents. If the previous incidents had resulted in yielding of material or had initiated cracks, very small torque cycles could extend the damage. There were recommendations that the industry should perform studies and tests to better define fatigue-life models for the shaft sizes and geometries used in large turbine generators. There also were recommendations that better monitoring should be installed in generating plants to measure the response of turbine generators to these disturbances. Recently, interest was renewed when torsional cracks were discovered at the Dresden Nuclear Plant near Chicago, in the United States. Units 2 and 3 at this plant were rated at 828 MW when they went into service. Unit 2 began service in 1970 and Unit 3 began service in 1971. When Unit 3 was shutdown in October 2004 for a regularly scheduled refueling outage an inspection was performed on the generator to determine the reason for a change in lateral vibration. This inspection revealed an approximately thirteen-inch crack on the generator shaft that ran under the coupling to the low-pressure turbine. Subsequently, based on the Unit 3 inspections, Unit 2 was shutdown to perform similar inspections. These inspections revealed a similar crack on the generator shaft of Unit 2.

Although there is general agreement that the Dresden machines were more vulnerable than newer units due to the specific geometry of the keyways under the couplings, there is no agreement on the oscillation modes or knowledge of the system disturbances that might have initiated or propagated these cracks. The nature of the cracks indicated that the machines experienced a small number of large overloads that significantly extended the cracks. Between these overloads there was evidence that the cracks grew slowly due to high cycle fatigue at relatively low stress amplitudes.

## 3.3 List of Events

The EPRI Report [1] contains a table of events that resulted in actual damage to turbine generators. This tabulation relies on events discussed in technical papers and in presentations at technical conferences. There is no formal reporting mechanism. In many cases the damage is due to high cycle fatigue and crack surfaces show a number of intermittent overload indications separated by areas of slow fatigue growth. These indications have been interpreted to show that the machine occasionally experiences a large amplitude disturbance with a much greater number of small disturbances. The stress levels required to extend cracks once they have initiated are not precisely known, but may be very low. For incidents of torsional resonance near 120 Hz (on 60-Hz systems, or 100 Hz on 50-Hz systems) the continuous oscillation resulting from unbalanced phase currents in the generator can create more than 10 million cycles per day and damage has been known to occur in less than 5 days after a change in the unit resulted in the resonant condition.

The authors believe that the damage listed in Table 3-2 is much less than the total actual industry damage due to system interactions. Many repairs were done without conclusive root cause analysis. These incidents are not reported to the industry and there is no formal mechanism to identify or report large amplitude transient events. Although there are periodic recommendations that monitoring equipment that measures transient electric power and resulting shaft oscillations be installed on large turbine generators, there are few installations. The separation of generating and transmission personnel resulting from industry de-regulation has further eroded the industry's ability to determine the extent of these interactions.

**Table 3-2**
**Reported Damage to Turbine Generators Resulting From System Interactions.**

| Unit | Utility | Year of Event | Rating | RPM | Failed Components | Failure Mechanism | Comments |
|---|---|---|---|---|---|---|---|
| Mohave Unit 2 | Southern California Edison | 1971 | 483 MVA | 3,600 | Generator shaft under the collector ring | Two separate incidents due to SSR | The second incident occurred before the root cause was discovered. |
| Prairie Island Unit 1 | Nuclear Management Corporation | 1974 | 630 MW | 1,800 | LP turbine L-1 and L-2 turbine blades | High cycle fatigue | Two incidents due to torsional resonance near 120 Hz. |
| Gas Turbines | Consumers Power | 1975 | 21 MW | 3,600 | Turbine - Gen shaft | Hollow shaft rupture | Out of phase synchronization. |
| Maanshan | Taiwan Power | 1985 | 1,057 MVA | 1,800 | Eight last stage blades and alternator shaft | High cycle fatigue | Torsional resonance near 120 Hz. |
| Monticello Unit 1 | Nuclear Management Corporation | 1985 | 570 MW | 1,800 | Fatigue life consumption | Torsional oscillations—high stress | 700-MW oscillation at HVDC inverter substation. Unit required rebalancing. |
| Comanche Unit 2 | XCEL / Public Service of Colorado | 1987 | 350 MW | 3,600 | Cracked generator shaft - Main coupling | Fretting fatigue | Postulated torsional oscillation at first torsional frequency due to nearby arc furnace SVC and unit PSS. |
| Susquehanna Unit 1 | PPL | 1993 | 1,050 MW | 1,800 | Two I-1 stage blade failures in LPC | High cycle fatigue | Torsional resonance near 120 Hz. |
| Comanche Unit 2 | XCEL / Public Service of Colorado | 1994 | 350 MW | 3,600 | Gen retaining ring fracture | Torsional high cycle fretting fatigue | Interaction with nearby steel mill that stimulated torsional mode near 117 Hz. |
| Port Washington | Wisconsin Electric Power | 1998 | 80 MW | 1,800 | Spindle mounted retaining ring cracks | High cycle fatigue | Postulated interaction with steel mill. |
| South Texas Project Unit 2 | South Texas Project Nuclear Operating Company | 2002 | 1,300 MW | 1,800 | One LP blade fracture. Other LP blade cracks | High cycle fatigue | Torsional natural frequency near 120 Hz. |
| Dresden Units 2 & 3 | Exelon / Commonwealth Edison | 2004 | 912 MW | 1,800 | Cracked Generator shafts at main coupling | High cycle fatigue—fretting | Postulated intermittent oscillating torques due to system disturbances. |

# 4
# METHODS FOR IDENTIFYING THE VULNERABILITY OF TURBINE GENERATORS TO TORSIONAL INTERACTION

## 4.1 Methods for Identifying the Potential for SSR and DDSO

Subsynchronous resonance (SSR) and Device Dependent Subsynchronous Oscillation (DDSO) as described in the previous section are phenomena limited to generating facilities in the vicinity of series compensation or large power electronic devices. Thus, these are special cases and require specialized studies. A thorough account of the commonly used techniques for identifying the potential for torsional interaction due to SSR and DDSO is presented in Appendices C and D, respectively, together with a discussion of the mitigation techniques and methods for more detailed studies.

## 4.2 Transient Torque Phenomena

General torsional interactions, as described in Section 2.4, occur as a consequence of faults and normal switching operations and are primarily a transient torque phenomenon. That is, large torque oscillations at torsional frequencies are excited by a switching event on the transmission system. These will occur on any turbine-generator. The observed transient torques can be further aggravated if the turbine-generator is in the vicinity of a series capacitor—the details of the series capacitor overvoltage protection system will also affect this impact.

In this section, based on a generic model (see Appendix E for details of the model) a thorough study is performed to bring out some general guidelines and "rules of thumb" for identifying the "zone of vulnerability" of turbine-generators to such phenomenon.

## 4.3 Selection of Torque Levels for Identifying the Zone of Vulnerability

To date there have not been any industry standards defined for either shaft stress levels or number of stress cycles that machines can withstand. The capability of individual machines to endure torsional stress duty has been defined by detailed analysis usually performed by the manufacturer. These studies have resulted in a general guideline that if planned switching actions are controlled to limit the sudden (transient) change of generator output power to less than 0.5 pu of the rating of the machine, the turbine generator shaft system should not be damaged, and generally only be exposed to less than 0.01 percent loss of life per event [40]. Here by planned switching action is meant reclosing of a transmission line (successful and complete reclosure after any faults have cleared), synchronization of generating units, routine switching of other transmission devices (e.g. shunt and series capacitors, series reactors and phase-shifting transformers in transmission lines etc.), as opposed to severe disturbances such as bolted 3-phase to ground faults that may result in network switching events as a result of the action of protective equipment.

An IEEE/ANSI standard for electric generators [42] provides some guidance for torque levels that the turbine generator must withstand. This standard states: "A generator shall be designed so that it can be fit for service after experiencing a sudden short circuit of any kind at its terminals while operating at rated load and 1.05 per unit rated voltage, provided that the fault is limited by the following conditions:

- The maximum phase current does not exceed that obtained from a three phase sudden short circuit.
- The stator winding short time thermal requirements are not exceeded.

A generator shall be judged fit for service after the incident if it requires no more than the following minor repairs:

- For the stator winding the term "minor repairs" implies that some attention to the end turn bracing system and to surface coatings of coil ground insulation may be necessary to ensure that the winding will withstand a maintenance high potential test after the repairs. The term "minor repairs" does not imply replacement of stator coils or ground insulation repair.
- For the rotor shaft "minor repairs" are those that can be made without removing the rotor such as some attention to coupling bolts, couplings and rotor shaft balancing to ensure that shaft dynamic motion and bearing vibration will be within acceptable limits after the repairs."

Although the standard was originally written to apply to the electric generator, designers have used it to establish the minimum capability of the turbine generator shaft system. These designs assure that the stress levels at the locations along the shaft with the highest torque do not exceed the yield strength of the material during these transients. Although this stress level is far above the fatigue limit of the material, these transients are not expected to occur more than once or twice in the life of the machine. Several previous technical papers have stated that this standard may not be a conservative design criterion for turbine generator shaft systems [17], [36]. These faults have a step change in output power from full load to nearly zero plus very large 60- and 120-Hz torque oscillations for machines operating in a 60-Hz network. The major shaft sections are most responsive to low frequency torque oscillations and may not be as severely stressed by this fault as by other system switching events. The fact that this standard has been used to judge the adequacy of shaft designs leaves some uncertainty about the ability of the large turbine generators to withstand system transients.

For this report the screening criteria to establish a zone of vulnerability around the turbine generator is selected to be the peak torque for each shaft section for the most severe terminal short circuit. This is less conservative than peak torque levels from a line switching event that caused a sudden power change of 0.5 per unit (50% of generator rating), but one goal of this study is to examine the general conclusions of a number of the technical papers. This conclusion was that the turbine generators should not experience torsional failures for the numbers of system faults that would normally occur in transmission networks provided that automatic high speed re-closing was removed from the lines directly connected to the generation bus. For this conclusion to be true, it would seem that the peak torque levels should be less than those experienced for a terminal fault on the machine.

This discussion does not apply to turbine-generators that have torsional frequencies near twice system operating frequency (120 Hz in 60-Hz systems or 100 Hz in 50-Hz systems). The spring mass models employed for the studies in this project are not detailed enough to show response of the shaft systems to electrical torque at these frequencies. Incidents that have been shown to be caused by the response of the turbine-generator rotor system to twice operating frequency electrical torque occurred because the sensitivity of the machine at this frequency was not known prior to the incident. Complex models calibrated by highly instrumented tests have improved the ability of the manufacturers to design machines that are not sensitive and to make modifications to reduce the sensitivity of the machines that have sustained damage.

The only standards that directly address the ability of the turbine generator to withstand unbalanced (negative sequence) phase current are those related to the heating that occurs to the generator rotor. They do not address the localized stress that may occur if the turbine generator shaft system has a torsional resonance that can be excited by the double frequency torque that the unbalanced (negative sequence) current applies to the generator rotor. The very low damping of the rotor system allows amplification factors of greater than 400 for some of these modes. When these resonances are discovered, modification of the rotor system to either move the natural frequency or change the mode shape to reduce the stress buildup are the solutions that have been successfully applied.

Most of the technical discussion about the double frequency torsional issues has focused on the nearly continuous negative sequence component of generator armature current. When this current is measured on operating machines it is typically less than 2% of the rated current of the machine. The very low mechanical damping of the rotor system allows amplification that results in fatigue damage when there is a natural frequency that is close enough to the double frequency and is responsive to torque applied along the generator rotor. Studies have shown that this responsive mode must be within 2 Hz of the double frequency (120 Hz in 60-Hz systems) to sustain damage for the continuous negative sequence current levels allowed by the rotor heating standards. These studies have not addressed the much larger transient torques resulting from unbalanced system faults.

## 4.4 Simulations to Identify Critical Cases

Figure 4-1 shows the model of a generic system, described in more detail in Appendix E. As a first step, faults were simulated followed by normal clearing of the faulted transmission line on almost all of the transmission lines in the system. In addition, all combinations and permutations of fault scenarios were investigated. These include 3-phase to ground, single-line to ground (phase A), phase-to-phase to ground (AB-ground), phase-to-phase (AB) and 3-phase ungrounded faults with normal clearing (3 cycles[4-1]) at each end of the line.

In addition, 3-phase to ground, single-line to ground (phase A), phase-to-phase to ground (AB-ground), phase-to-phase (AB) and 3-phase ungrounded faults were simulated at the generator terminals of generator SM1 (one of the two identical 1,800-RPM units) and SM3 (the 3,600-RPM unit)[4-2]. Furthermore, in keeping with the standards [42], the generator terminal faults were simulated with the initial steady-state voltage of the generator being at 1.05 pu (105% of rated voltage) and with a typical grounding resistor modeled on the generators neutral point[4-3]. The results of the simulations are summarized in Table 4-1. In this table, for each case simulated, the peak transient mechanical torque is shown on each shaft segment of the three machines, in per unit (pu). In each case the mechanical torque on a shaft segment is the torque developed between adjacent masses on that shaft and is in per unit on the base of the rated torque of that turbine-generator (rated torque = rated MVA/rated speed).

As an example, let us consider one of the large 1,800 RPM units. For these units the division of power among the eight turbine sections is equal at 12.5% (see Appendix A). Figure 4-2 shows this shaft model. Thus, in steady-state the torque developed between mass 1 and mass 2, on shaft segment 1, would be $0.9 \times 0.125$ pu (0.9 power factor). On shaft segment 2 would be twice this amount, and so on until we get to segment 8, which should sustain the full torque developed by all the turbines. Thus, when we look at the results in Table 4-1 we are looking for peak transient torques that represent a significant deviation from these steady-state values.

**Note:** In Table 4-1, peak torques are shown only for physical shaft segments. That is, for the 1,800-RPM machine torques are given only for shaft segments 2, 4, 6 and 8, which are actually physical shafts that join adjacent double-flow turbines. For the 3,600-RPM machine, however, the model provided had one mass to represent each double flow turbine and thus there are five physical shafts.

[4-1] Note to be more precise, primary clearing on the near end of the line was done in 3 cycles, while it was assumed that for such transmission lines telemetry would be available and thus the remote end was cleared in 4 cycles assuming one cycle for communication for transfer tripping.

[4-2] Note: The 1,800-RPM unit model is the model of an actual nuclear turbine-generator. Similarly, the 3,600-RPM unit model is the model of an actual large thermal turbine-generator.

[4-3] Some sensitivity analysis showed, that as expected modeling the generator neutral grounding resistor had no impact on the simulated transient torque results for balanced 3-phase faults and only affected the resultant transient torques observed for fault on the power system (i.e. grid connected to the high voltage side of the generator step-up transformer) in the third decimal point (i.e. roughly 1% or less). This is as expected since the delta-Y-grounded generator step-up transformer provides for isolating ground faults between the power system and the generator. Thus, for simplicity the simulations of faults on the power system were performed without modeling generator neutral grounding resistance.

Summarizing the results in Table 4-1, the following comments are pertinent:

- The electrically closer in faults have the greater impact (i.e. result in higher peak transient torques). Faults on remote lines or remote ends of lines directly emanating from the plant have a markedly lesser transient torque impact than close in faults.
- Multi-phase faults (3-phase and 2-phase faults) have greater impact than single line to ground faults. (This would not necessarily be true if the modeled units had near 120-Hz modes).
- The cases with maximum peak torque for faults on the generator terminals and in the network are highlighted. The maximum transient torque occurring for machine terminal faults should be tolerable at least once in the life time of the machine (see ANSI standard 50.13). Thus, by comparing these with the peak torques observed for the system faults one can identify the critical system faults for further study.
- The step change in torque due to the fault and fault clearing is the dominant factor on torsional response. Faults on all lines emanating from a power plant were considered. As can be seen there are slight differences in the results of faulting and tripping adjacent lines emanating from the SM1/SM2 power plant (e.g. fault and trip of line 1-2 at the bus 1 end as compared to fault and trip of line 1-3 at the bus 1 end). This is because although the initial fault transient is the same for both cases (same fault type and location), once the line trips the transient electrical response of the generators is slightly different (in one case we trip one of two parallel lines, while in the other case we trip a line that is interconnecting to a large adjacent system—modeled by an equivalent source here). Never-the-less, the differences are small.

Based on these results two cases (3-phase fault bus 1 end of line 1-2 and 3-phase fault bus 4 end of line 4-13, Table 4-1), which yielded the highest transient torques, were selected for further studied through sensitivity analysis. Also, plots have been provided in Appendix F for some of the selected critical cases.

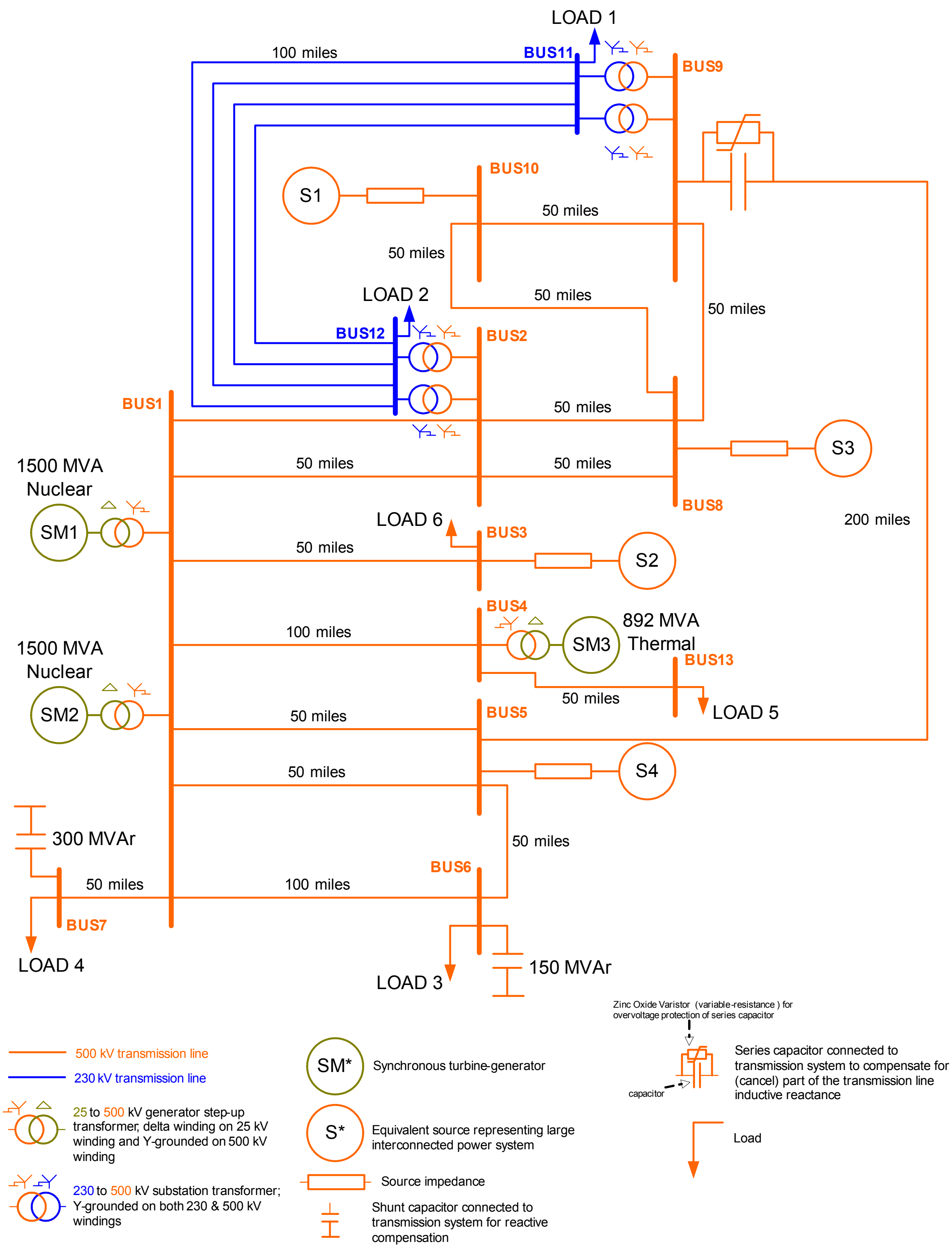



**Figure 4-1**
**Diagrammatic Representation of System Model**

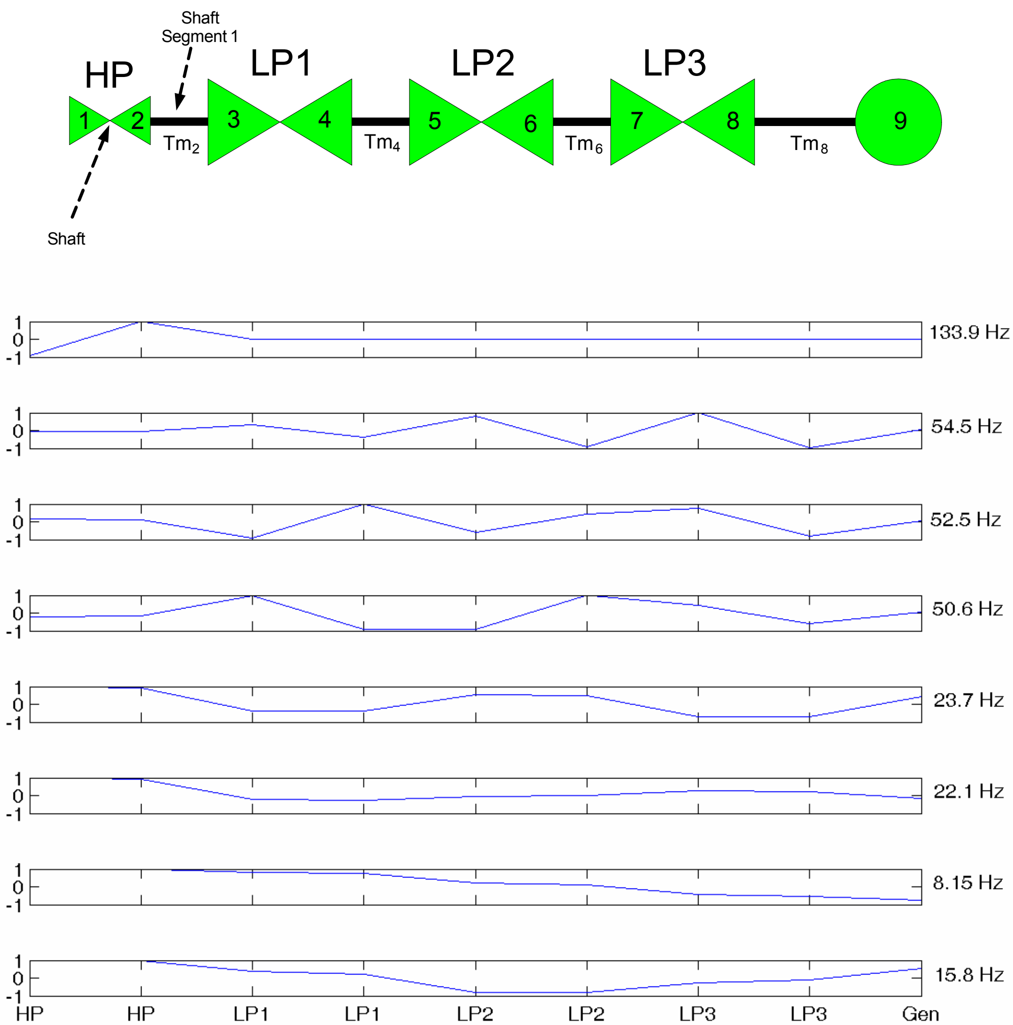



**Figure 4-2**
**Lumped mass model and torsional modes for the shaft of machine SM1 & SM2 (1,800-RPM machine). The turbines are double-flow turbines.**

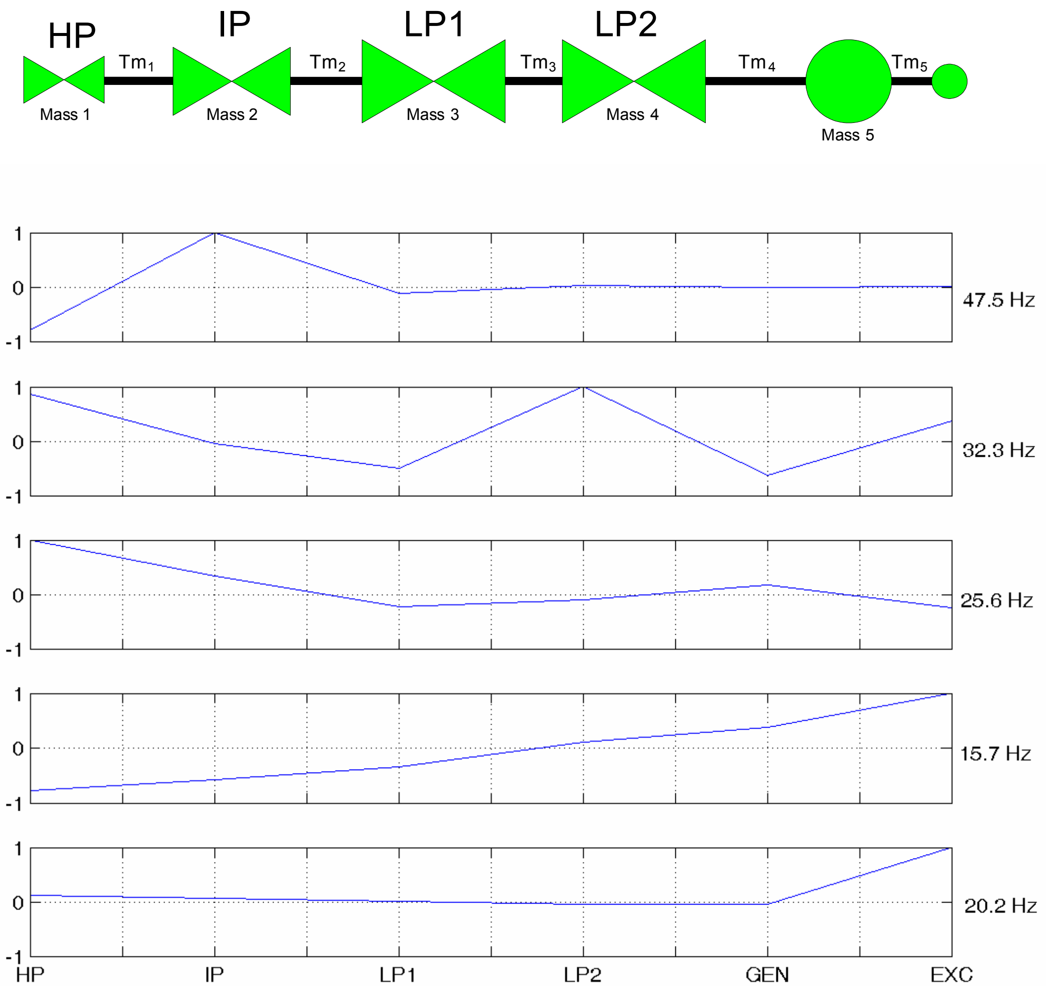



**Figure 4-3**
**Lumped mass model and torsional modes for the shaft of machine SM3 (3,600-RPM machine). The turbines are double-flow turbines.**

## 4.5 Sensitivity Analysis

Based on the results in the previous section two clear conclusions may be drawn:

- 3-phase faults near by the plant appear to result in the most significant peak torques.
- A fault at (or immediately outside) of the power plant substation on the high-side of the generator step up transformer appears to have the greatest transient torque impact of all the system faults simulated.

From these observations, the two lines 1-2 and line 4-13, were chosen for further sensitivity analysis. Sensitivity analysis is needed to fully assess the impact of various parameters in the unfolding of a disturbance on the resultant transient torque response of the generating units. We need to identify the influence of fault clearing time, high-speed reclosing, distance of the fault to the plant and other parameters on the level of torsional interaction.

The following parameters were varied for the purposes of sensitivity analysis:

- Duration of the fault.
- Initial terminal voltage of the machine under study.
- Initial megawatt loading of the machine under study.
- Distance of the fault to the plant.
- Short circuit level of the system.
- Number of adjacent identical generators at the power plant.
- Initial steady-state transmitted power on the faulted line.
- Point of inception of the fault on the ac wave form (that is, whether the fault occurs at the point during the 60-Hz cycle when the voltage is a maximum, or near zero etc.)
- Out of phase synchronization of the generator upon start-up.
- Manual reclosing of a transmission line with various load angles. When attempting to reclose (re-insert into the system) a transmission line, there will be a phase angle difference between the system voltages on the opposite sides of the circuit breaker that is used to completely re-insert the line into the transmission system. This phase angle difference (referred to here as the "load angle") is determined by power flow in adjacent paths on the transmission network and is an indication of the initial transient inrush of power into the line once it is re-inserted into the network. Thus, depending on the initial "load angle" the impact on the units in the plant will vary.
- High-speed reclosing of the line. That is, various cases are simulated to emulate the automatic reclosing of transmission lines back into the transmission system after the inception and clearing of a transmission fault. Most faults on extra-high voltage (115 kV and above) overhead transmission lines are temporary (e.g., tree contact, lightning strikes etc.). That is, once the transmission line has been isolated by the action of the protection system (opening line end circuit breakers) the fault will typically have disappeared. Hence, by automatically reclosing the line within a fraction of a second after it has opened there is a high probability that the fault may have already been removed. In the absence of automatic high-speed reclosing, longer duration outages could be experienced unnecessarily. Successful automatic high-speed reclosing tends to enhance stability and overall system reliability, and hence is widely used particularly on extra-high voltage transmission lines (115 kV and above) where prolonged outages have the greatest adverse impact on system performance. However, one aspect of automatic high-speed reclosing that cannot be ignored and must be investigated is the possibility of reclosing into a permanent fault (e.g. grounding switches left on bus work after maintenance work). This can adversely impact system stability as well as have adverse impact on generator torsional oscillations. It is this phenomenon that is investigated here with variations in the reclosing time.

- Several special cases were also investigated. For example, a stuck breaker fault that results in the tripping of an adjacent turbine-generator as well as clearing the transmission line.

Before the results of the sensitivity analysis are presented, it is pertinent to define a few terms related to electrical network faults and fault clearing. Figure 4-4 shows an example electrical system layout on either side of an extra-high voltage transmission line.

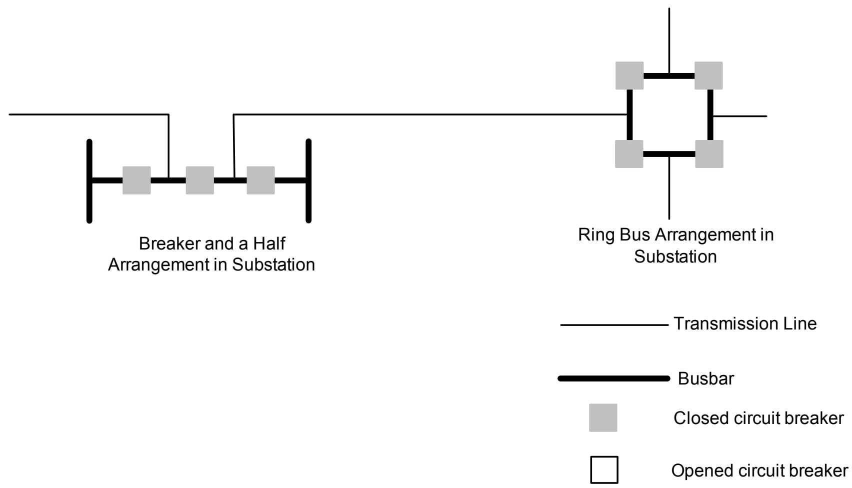



**Figure 4-4**
**Example electrical system layout at the ends of an extra-high voltage transmission line. The lines are interconnected by an arrangement of circuit breakers and busbar.**

Figure 4-5 shows the sequence of events for a failed automatic high-speed reclosing (HSR) event. This helps to explain not only HSR but fault clearing in general. Looking at the figure, initially all breakers are closed and the line between bus 1 and 2 is in service. Then at time t = 0 a fault occurs near the bus 1 end of the line. This is detected by distance-relays at the bus 1 substation and so the breakers at the bus 1 end open (starting the process to clear the fault) at time t = 3 cycles—that is, 3 cycles of electrical frequency (in a 60-Hz system this corresponds to 3/60 = 0.05 seconds). Once these breakers open, through automatic controls connected by telecommunication (telemetry) a signal is sent to the remote end of the line to open the breakers at the other end and completely clear the disturbance—this process of detection and telemetry typical takes another cycle or so. Now, after a short delay (12 cycles) the bus 1 end breakers automatically reclose in an attempt to reclose the line. Since in this case the fault has persisted, they once again open in 3 cycles, resulting in a failed HSR attempt. In the simulation sensitivity analysis one of the primary parameters that is varied is all the delays described here, the initial clearing time of the close end breakers, the subsequent delay in telemetry in opening the remote end breaker and for HSR the delay between line clearing and subsequent attempted line reclosure. In practice, all these parameters are adjustable in the relay control logic; however, there will be statistical variations in the actual delays of typically up to one half of a cycle. For the primary clearing time (i.e. the delay between initial fault detection and opening of the bus 1 breakers in our example) values between 2.5 cycles to 6 cycles are typical for extra-high voltage transmission lines, with smaller clearing times being applicable to higher voltages. For example, on 500-kV networks typical clearing times are between 2.5 to 3 cycles. The lower limit on this clearing time is driven by the physical limits of most present day circuit breaker technology.

Older circuit breakers will tend to have longer clearing times. In this sensitivity analysis the various delays have been purposefully altered across the possible and typical range of values.

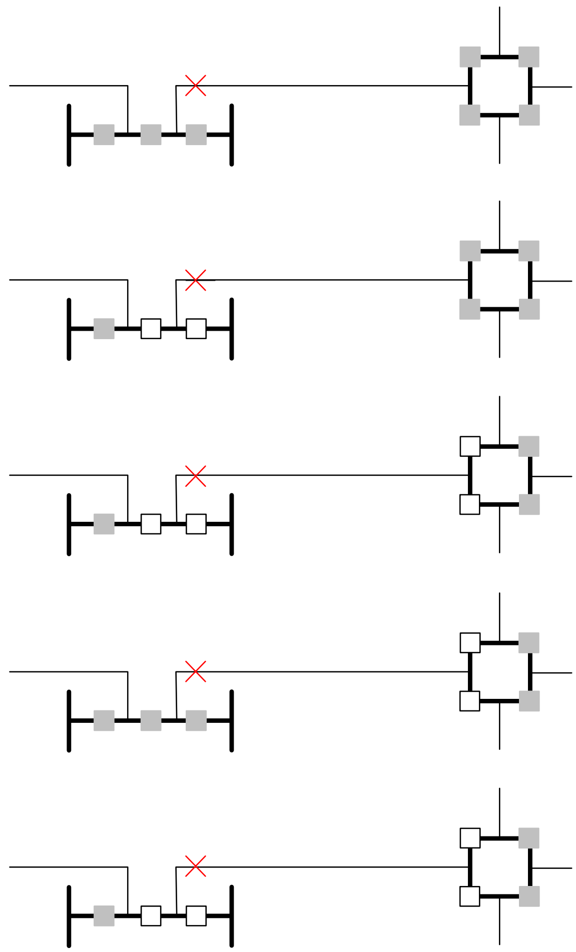


**Figure 4-5**
**Sequence of events for a failed automatic high-speed reclosing event.**

## 4.6 Discussion of Sensitivity Analysis Results

In the discussion that follows, the symbol $Tm_i$ represents the mechanical torque associated with the i[th] shaft segment in the turbine-generator shaft model (see Figures 4-2 and 4-3). From the sensitivity analysis performed, the following conclusions may be drawn:

1. **Type of Fault:** The type of fault does affect the level of torsional interaction (excitation of the modes). Typically, multi-phase faults are the worst (Table 4-1). The exception to this rule is perhaps turbine-generator shafts with near 120 Hz (100 Hz on 50-Hz systems) torsional modes. For such units the negative sequence currents during unbalanced faults (e.g. single-line to ground faults, which are typically more common that multi-phase faults) and system conditions can be more detrimental. Also, as the results of SM1 have shown, although the transient torques due to single phase faults are less than those of multi-phase faults, in some cases the sequence of switching actions associated with single phase faults in

the network can also result in transient torques that exceed the transient torques observed for a three phase fault at the machine terminals.

2. **Distance of Fault:** As the fault location gets further away from the power plant, the level of torsional interaction droops almost exponentially (Figure 4-6).

3. **Normal Fault Clearing Time:** The clearing time of the fault has a significant impact on the level of torsional interaction. This is primarily driven by the modal frequency of the torsional modes. For example, in Figure 4-7 it is observed that the maximum transient torque on all the shaft segments (segments 2, 4, 6 and 8) of the 1,800 RPM unit peaks around a fault clearing time of 3.5 to 4 cycles. Looking at Figure 4-8, it is seen that the torsional response of these shaft segments is dominated by the 8.15-Hz and 23.7-Hz modes. A half cycle period of the 8.15-Hz mode is equal to 3.7 cycles of system fundamental frequency (60 Hz), while a half cycle period of the 23.7-Hz mode is equal to 1.3 cycles of system fundamental frequency. Thus, a 3.5 to 4 cycle fault clearing time corresponds roughly to odd multiples of half-cycles of both torsional modes, which means that the clearing time is such that the torque transient due to clearing of the fault reinforces the initial transient started by the inception of the fault thereby magnifying the resultant response. This is consistent with previous observations in the literature [2]. The same behavior is true of the 3,600-RPM machine (Figure 4-9). For extra-high voltage transmission lines, the remote end of the line is transfer tripped by telemetry when a fault is detected at or near one end by distance relays (see discussion above for explanation). This delay can be typically between one to two cycles. Though not shown here, sensitivity analysis was performed with respect to varying this delayed clearing of the remote end of the line between one half to two cycles. It was observed that variations in this delay do not have a significant impact on the torsional interaction.

4. **High-Speed Reclosing of Lines:** For high-speed reclosing (HSR) of lines coming into the plant we see a similar behavior. That is, if the reclosing time is an odd multiple of half-cycle of a dominant torsional mode, then the peak transient torque is amplified. In the case of unsuccessful reclosing (i.e. reclosing back into a fault) at the plant end of a line, between 3 to almost 4 pu transient torques may occur, which may result in significant fatigue life expenditure of the shaft (Figure 4-10). As shown in Figure 4-10, for the 1,800-RPM machine the worst reclosing time period is 11 cycles; the figure shows results for unsuccessful reclosing.

   The worst case was then repeated for four other scenarios: (i) successful reclosing of the line (i.e. not reclosing back into a fault), (ii) reclosing back into a fault, but reclosing the remote end of the line first (i.e. the end of the line furthest from the plant), and (iii) HSR of line 2 – 8, which is one bus removed from the plant, and (iv) single-pole-switching—this is a much more common practice where for the more prevalent single-line to ground faults, the single phase that is faulted is opened and reclosed in the hopes of removing the fault. In these cases the peak transient mechanical torques were:

   i. $Tm_2$ = 0.72 pu, $Tm_4$ = 1.71 pu, $Tm_6$ = 2.16 pu and $Tm_8$ = 2.28pu

   ii. $Tm_2$ = 0.71 pu, $Tm_4$ = 1.70 pu, $Tm_6$ = 2.16 pu and $Tm_8$ = 2.30pu

   iii. $Tm_2$ = 0.46 pu, $Tm_4$ = 1.30 pu, $Tm_6$ = 1.81 pu and $Tm_8$ = 1.78pu

   iv. $Tm_2$ = 0.35 pu, $Tm_4$ = 1.06 pu, $Tm_6$ = 1.52 pu and $Tm_8$ = 1.45pu

These results show that successful reclosing, as opposed to reclosing back into a fault does have less of an impact, as expected. Similarly, reclosing the line at the remote end, even if back into a fault, significantly reduces the impact of the switching event. HSR on lines that are not directly connected to the plant also have a significantly lower impact. However, as shown here, even when one bus away from the power plant the transient torques due to HSR may still exceed the endurance limit of the shaft and result in some fatigue loss of life. Finally, in the case of single-pole switching (the case here was of unsuccessful single-pole switching back into a fault and then clearing the whole line, with the fault being on the plant end of the line) the transient torques are much less than for multi-phase faults and reclosing.

The fact that with unfavorable timing all of the reclosing cases studied could produce peak torques on at least one shaft section that are larger than the terminal short circuit on the generator is surprising. It has been generally assumed that HSR would be acceptable if it were not on a transmission line directly connected to the generator bus. Although the highest peak torque for a fault on the line that is one bus away from the plant (case iii) is about half the value for the fault at the high side of the generator transformer, the peak shaft torque on the shaft between LP2 and LP3 is 80% higher than for a terminal short circuit. This result reinforces the statements of plant personnel that there are strong noise or vibration changes in the plant caused by relatively remote reclosing operations. Case iv (single pole tripping and reclosing for single line to ground faults) represents a common practice for plants that have a minimum number of transmission circuits. It is not uncommon for the first reclose operation to be unsuccessful and the protection will often follow the three phase trip with a second reclose attempt. This attempt usually has a time delay of one second or more and usually the far end on the line is closed first. Since torsional oscillations persist for many seconds, these additional switching operations provide more opportunity to reinforce the torsional stress.

Although this investigation of HSR was very brief, it indicates that an in depth investigation of the HSR practices in the transmission network is required to fully explore the ZoV for a generating plant. The investigation may extend to lower voltage networks where there usually are a greater number of faults. It will have to carefully model both the current timing of protective operations and modifications of the timing that would minimize the impact on the generating plant. In summary, HSR reclosing poses a high risk for torsional interaction for the turbine-generator. The risk may even increase when transmission line or substation buses are taken out for maintenance. Thus, plants are strongly advised to discuss the issues with the transmission operator.

5. **Loading of the Line and Generating Unit:** Simulations were performed for varying line loading levels and the results clearly showed that the loading of the line that is faulted and tripped does not have a significant effect on torsional interaction. Conversely, the loading of the turbine-generator itself has a great impact on torsional interaction—the higher the initial megawatt load on the machine, the greater the torsional interaction (Figure 4-11).
6. **Number of Units On-Line:** Figure 4-12 clearly shows that with more units on-line and connected to the same point in the grid (at the power plant) the less the transient torque impact on each unit for a given disturbance—this is because they tend to share the impact of the disturbance. Also, as shown in the figure, as the disturbance moves further way from the plant this effect is more pronounced, as one might expect from the results of Figure 4-6.

7. **Higher overall systems short circuit strength:** A few sensitivity cases were simulated to emulate various overall system short circuit strength (i.e. varying the amount of available short circuit current due to more remote generation being on-line). This was done by scaling the source impedance of the four equivalent sources at the electrical system boundaries. Four cases were simulated, first by doubling all source impedances (essentially halving the short circuit level of the equivalent sources) from the initial case (as described in Appendix B), then halving the source impedances (doubling short circuit level) and then making the source impedances one quarter of the original value (four times the short circuit level). The network topology (line lengths, number of lines etc.) was not changed.

   Figure 4-13 shows the results of this analysis. As shown, the peak transient torques were not enormously affected, however, clearly an increase in the system short circuit strength results in an increase in the peak transient torques. This is because the higher short circuit strength means faster and higher voltage recovery after a fault and thus a slightly larger transient in electrical torque and subsequently a larger transient in mechanical torque/stress. This is in contrast to the case of having more units on-line at the plant since in that case the units share the impact of the disturbance and thus the resultant impact on each unit is decreased.

8. **Point on Wave Timing of Fault Inception:** During a single cycle of 60 Hz the ac voltage at any point in the network will vary from zero volts to its peak value, back to zero, down to its peak value with the opposite polarity and then back up to zero (see Figure 4-14). Four cases were simulated to vary the point on the 60 Hz voltage waveform at which the initial transmission line fault incepts. The fault was initiated (on phase A) at $0^0$, $30^0$, $60^0$ and $90^0$ (see Figure 4-14). It was assumed that the fault initiated on the other two phases also at the exact same time. These sensitivities did not show any significant variation in the resultant transient torques. In practice it is difficult to know exactly at what point on the wave a fault will incept or the exact spread of time between inception on the various phases. One additional case was simulated where the fault was incepted on all three phases at $0^0$ (0 volts). This was done to impose the largest amount of dc offset on the initial fault inception. In this case the transient torque on the shaft segment between the generator and first LP stage increased by roughly 5% as compared to the other cases. Such an occurrence, in real life, is highly unlikely.

9. **Manual or Automatic Reclosing a Line at the Power Plant with a "load Angle":** Cases were simulated for reclosing of one circuit of line 1-2 (with both circuits initially out of service) with varying "load angle" across the closing breaker. When manually (by operator action) reclosing a transmission line (re-insert into the system), there will be a phase angle difference between the system voltage on the opposite sides of the circuit breaker that is used to completely re-insert the line into the transmission system. This phase angle difference (referred to here as the "load angle") is determined by power flow in adjacent paths on the transmission network and is an indication of the initial transient inrush of power into the line once it is re-inserted into the network. Figure 4-15 shows the transient in electrical power for three different load angles. The corresponding peak mechanical transient torques on machine 1 & 2 (both were in-service) were:

   <u>10 degrees:</u> $Tm_2$ = 0.25 pu, $Tm_4$ = 0.51 pu, $Tm_6$ = 0.74 pu and $Tm_8$ = 0.97 pu

   <u>30 degrees:</u> $Tm_2$ = 0.28 pu, $Tm_4$ = 0.61 pu, $Tm_6$ = 0.85 pu and $Tm_8$ = 1.08 pu

   <u>45 degrees:</u> $Tm_2$ = 0.3 pu, $Tm_4$ = 0.67 pu, $Tm_6$ = 0.91 pu and $Tm_8$ = 1.16 pu

These results confirm the general screening criterion defined in [40], which states that for network switching events that result in a transient (sudden) change in the average electrical power of a thermal turbine-generator of 0.5 pu (on machine MVA base) or less the resulting “loss-of-life would generally be expected to be negligible and can be quantified as less than 0.01 percent per incident.”

10. **Out-of-Phase Synchronization of a Unit:** Figure 4-16 confirms the commonly accepted rule that if a unit is synchronized more than 10 degrees out-of-phase, this could result in significant stress on the shaft (i.e. reaching close to those experienced for a terminal fault). The step change in generator power was very nearly 0.5 pu for the 15 degree out of phase synchronization and corresponding peak shaft torque on the LP3-Gen shaft was about one third the value for the most severe terminal fault. As shown, with increasing phase angle the initial electrical power transient can be exceedingly large. The consequent peak transient mechanical torques for these cases were:

    <u>15 degrees:</u> $Tm_2$ = 0.18 pu, $Tm_4$ = 0.48 pu, $Tm_6$ = 0.51 pu and $Tm_8$ = 0.52pu

    <u>30 degrees:</u> $Tm_2$ = 0.35 pu, $Tm_4$ = 0.95 pu, $Tm_6$ = 1.02 pu and $Tm_8$ = 1.02pu

    <u>45 degrees:</u> $Tm_2$ = 0.51 pu, $Tm_4$ = 1.42 pu, $Tm_6$ = 1.52 pu and $Tm_8$ = 1.53pu

11. **Initial Machine Terminal Voltage:** Sensitivity analysis was performed on varying the initial steady-state terminal voltage of the generator. As one might expect, as the initial terminal voltage increases so to does the resultant transient torque, almost linearly. There was some deviation from a linear increase since as the terminal voltage was increased, due to varying system conditions, the reactive power output of the generator also varied resulting in slightly different steady-state field voltage.

12. **Effect of Back-up Clearing:** Another rare, but possible circumstance, is back-up clearing (see glossary for definition). In this case, a circuit breaker may fail to operate resulting in a delayed clearing time and subsequent loss of additional system elements. Figure 4-17 and Figure 4-18 show the results for this back-up clearing scenario. The initiating event was a 3-phase to ground fault at the bus 1 end of one circuit of the line from bus 1 to 2. It was assumed that due to mechanically failure in the circuit breaker, one phase of the bus 1 end circuit breaker sticks (does not open) while the other two phases open in 4 cycles and the remote (bus 2) end breaker opens in 5 cycles. Due to the stuck breaker at bus 1, backup protection clears the circuit many cycles after fault initiation and also results in tripping the adjacent 1,500 MVA machine (SM2) —this is a plausible case for a breaker-and a half substation layout. The transient torques in some cases increase by as much as 11 % over the normal clearing event. This is driven by two factors (i) the back—up clearing time (i.e. if the total clearing time is an odd multiple of torsional frequency half cycles) and (ii) the transient electrical torque overshoot due to the loss of the sister unit at the plant (see Figure 4-18). It is extremely rare to have an event where all three-phases of a circuit breaker fail to open. None-the-less, one case was simulated (for the worst back-up clearing time) emulating such an event. This did not result in any significant additional increase in the transient torque.

13. **Effect of Series Capacitors:** Four different simulations were performed.

    i. Simulated a close in 3-phase fault and clearing of a single circuit of line 1-2 (fault at bus 1 end) with and without the series capacitor on line 5-9.

ii. Simulated a close in 3-phase fault and clearing of a single circuit of line 1-2 (fault at bus 1 end) with three new series capacitors introduced into the system. For this case the transmission lines from bus 1 to 2 (both circuits) and from bus 1 to 4 were increased in length to 150 miles and were compensated by 50% each. That is, on each of these three lines, a series capacitor was placed to eliminate 50% of the line reactance (i.e. a 60.87 μF capacitor). Each capacitor was assumed to be rated at 1,500 A RMS and was modeled with a 2.1 pu Zinc-Oxide varistor for overvoltage projection (using a typical GE voltage-current characteristic). The simulations showed that for an internal-fault (fault on the series compensated line) the varistor would need to absorb 15 MJ of energy—this would be quite typical of such an application. (See Figure 4-19.)

iii. Using the same scenario as in (ii), line 4-13 was faulted and cleared with a 3-phase fault at the bus 4 end.

iv. The protection system on the series capacitor on line 1-4 was changed for the last simulation. In this case it was assumed that the series capacitor is fitted with a modern protective system that allows fast by-pass of the capacitor and re-insertion once the fault has cleared for external faults. That is, faults not on the same transmission line as the capacitor. This is achievable with modern series capacitor overvoltage protection systems such as the Siemens thyristor-protected series capacitor or the ABB Capthor® fast by-pass technology. In this case we assume that for the fault and clearing on line 4-13 the series capacitor on line 1-4 is bypassed within 1 ms of the fault inception (which is typical of the protective systems mentioned) and is then reinserted into the system within 1 cycle after the fault is cleared.

For the case of with and without the series capacitor on line 5-9 (which is at least one bus away from both plants and radial to neither) there was no noticeable difference in the transient torques on the two units. When the series capacitors were moved up close to the plants, again for machines SM1 and SM2 there was no significant difference in the transient torques as compared to the case without the series capacitors. This is attributable to the fact that the plant has many transmission lines emanating from it and thus the electrical interaction with each machine is both reduced in magnitude and not at a frequency that interacts with the torsional modes of the plant.

However, for the case of faulting and tripping line 4-13, with the series capacitors as shown in Figure 4-20, the transient torques on the SM3 machine increased dramatically.(slightly above 3 pu on the shaft between the generator and LP). This is because in this case the loss of line 4-13 leaves the SM3 machine radially connected to the series compensated line (line 1-4). Furthermore, running the simulation for a longer period confirmed that for this case once SM3 is left radial on line 1-4 an SSR condition exists between the capacitor and turbine-generator shaft which results in exponentially growing shaft oscillations. The last interesting observation is related to the series capacitor protection system. Figure 4-20 shows the difference in the initial transient torque response with and without fast bypass and re-insertion of the series capacitor. As shown, with fast bypass and reinsertion the resultant initial transient torque is significantly less and comparable (in the initial transient period of 1 second) to the case without the series capacitor. Of course this is dependant on a number of factors, such as the reinsertion time and final overvoltage capacitor protection system design, however, in general this observation is in line with similar observations in the literature for gap protected systems [2]. The stored energy in the capacitor is being discharged in the case of fast bypass as opposed to being shared with the turbine-generator through the resonance process during the fault in the case where the capacitor is not bypassed. For this particular example, however, in the end the subsequent SSR condition is much more troublesome and would have to be mitigated either by completely bypassing a portion of the capacitor for this outage (without out reinsertion) to move the resonant peak away from the turbine-generator torsional frequencies or through other mitigation means such as thyristor-controlled series capacitors [34].

Owing to the network topology, some of the sensitivity cases above could not be repeated for the SM3 machine. However, most of the critical sensitivities were also simulated for SM3. The resulting trends in transient torque were the same as seen for SM1.

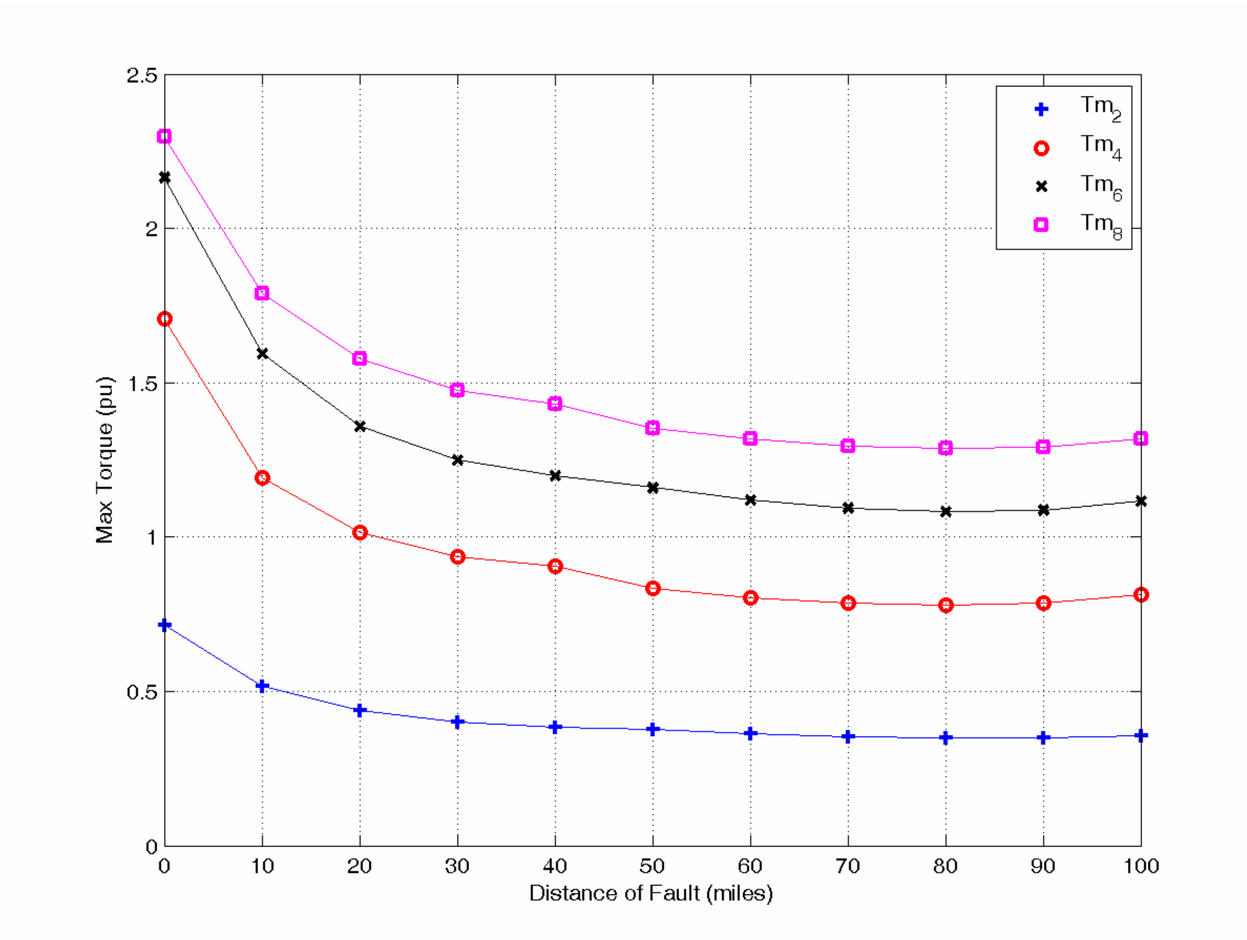



**Figure 4-6**
**Plot of peak torque (pu) on each relevant shaft segment for the 1,800-RPM machine (SM1) for varying distances along the line emanating from the plant. Circuit one of line 1–2 was faulted at starting at bus 1 end (0 miles) with a 3-phase to ground fault that is cleared in 4 cycles at the bus 1 end—the remote end was cleared in 5 cycles[4-4].**

[4-4] Fault clearing time was kept constant at the two ends of the line regardless of the fault distance – this was deliberate in order to vary one parameter at a time.

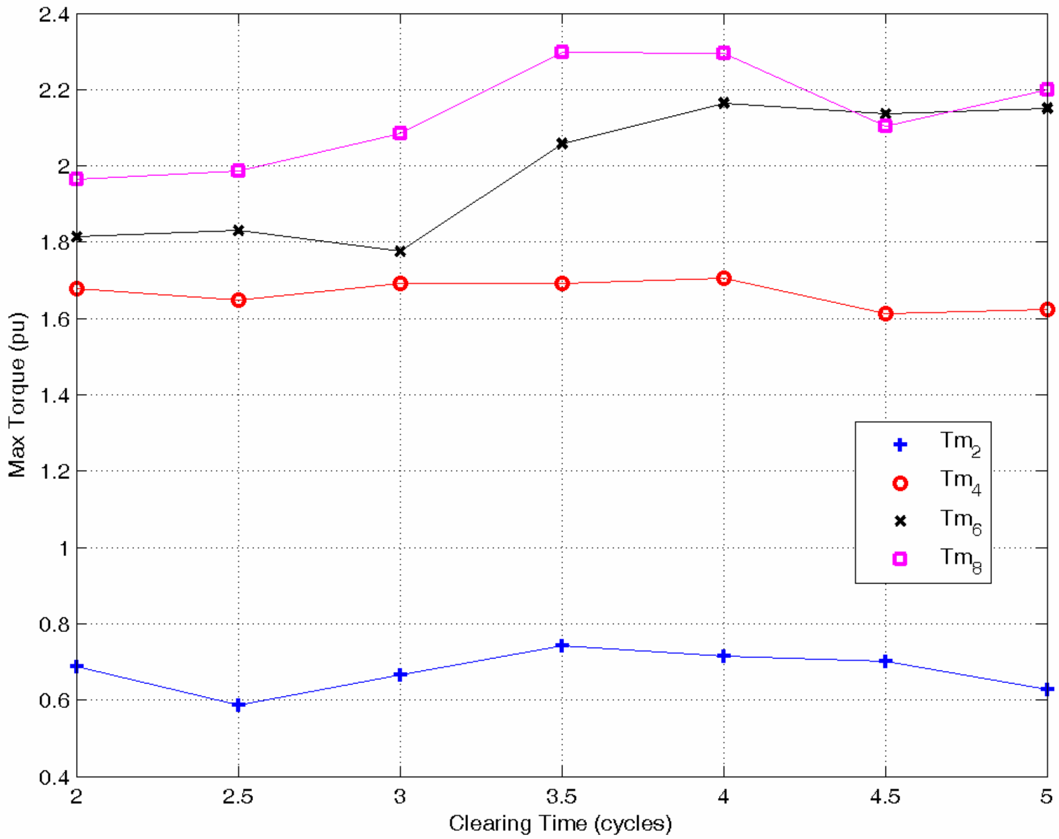



**Figure 4-7**
**Plot of peak torque (pu) on each relevant shaft segment for the 1,800-RPM machine (SM1) for varying fault clearing times. Circuit one of line 1–2 faulted at bus 1 end with a 3-phase to ground fault. Clearing times shown are for near end of the line, remote end (bus 2) clears 1 cycle after to allow for assumed delay due to telemetry for transfer tripping.**

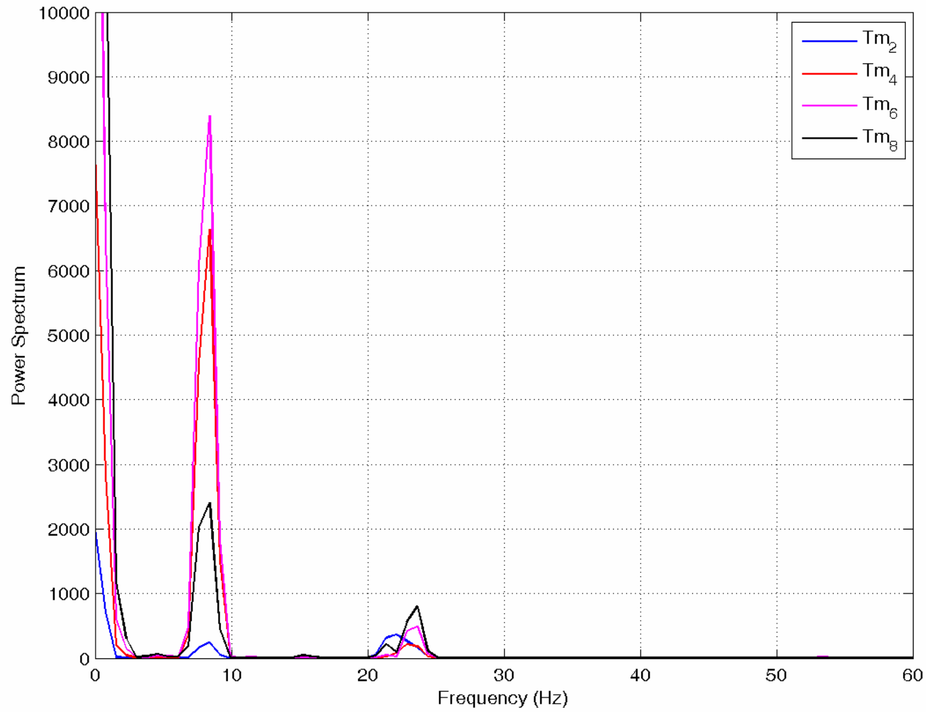



**Figure 4-8**
**Power spectrum of the mechanical torque response on shaft segments 2 ($Tm_2$), 4 ($Tm_4$), 6 ($Tm_6$) and 8 ($Tm_8$) for a 3-phase fault and clearing on Line 1–2.**

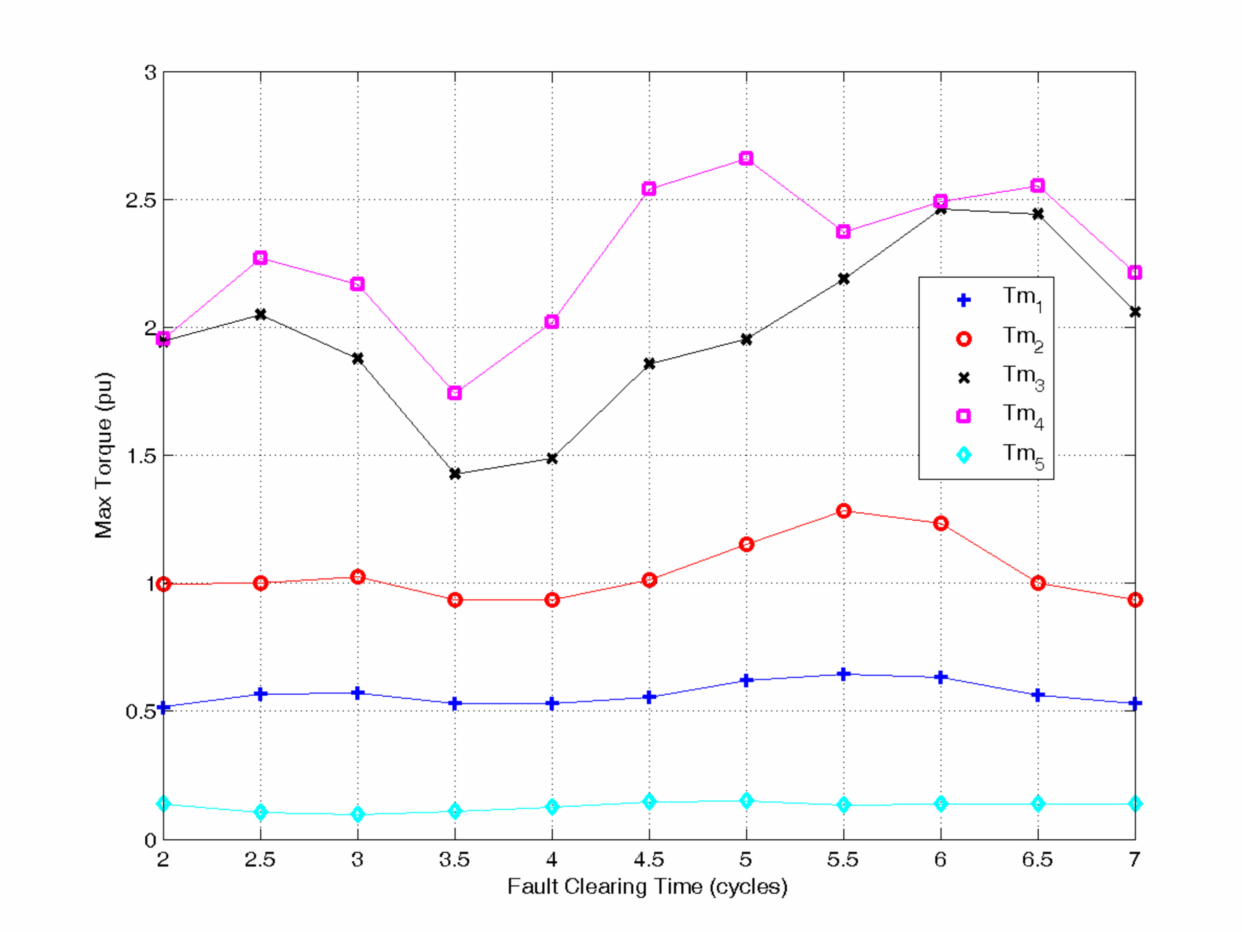



**Figure 4-9**
**Plot of peak torque (pu) on each relevant shaft segment for the 3,600-RPM machine (SM3) for varying fault clearing times. Clearing times shown are for near end of the line, remote end (bus 2) clears 1 cycle after to allow for assumed delay due to telemetry for transfer tripping.**

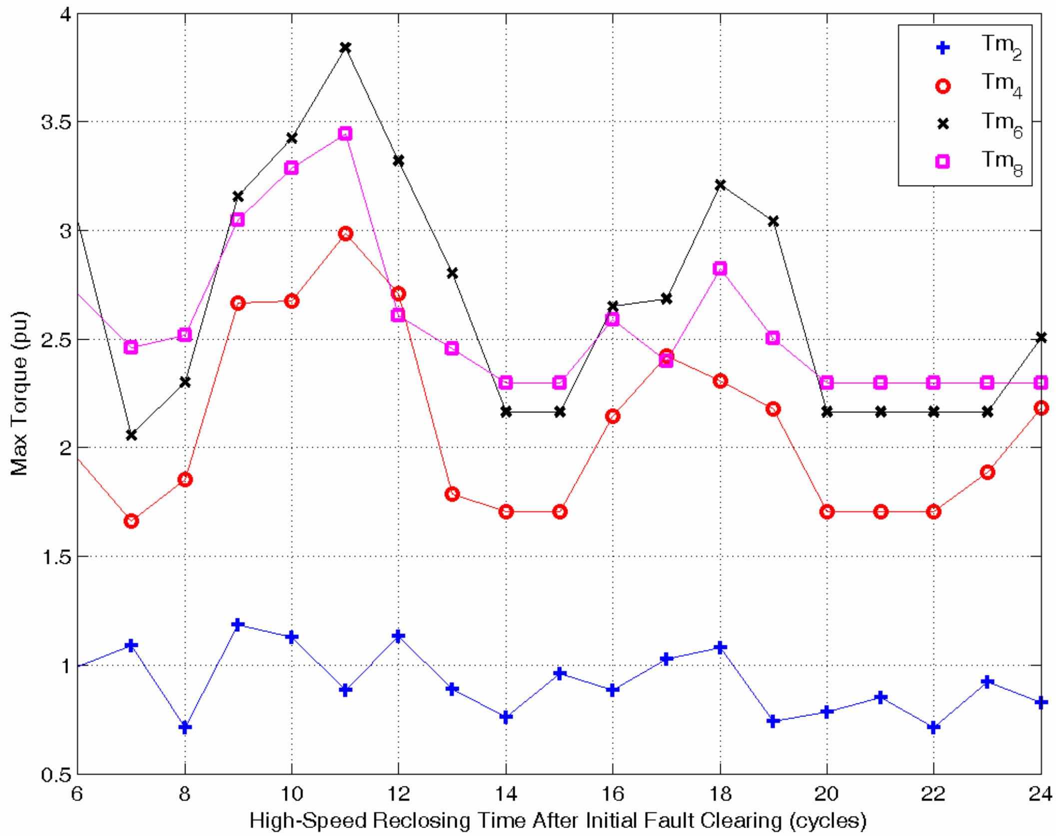



**Figure 4-10**
**Plot of peak torque (pu) on each relevant shaft segment for the 1,800-RPM machine (SM1) for varying automatic high-speed reclosing time. These are cases with unsuccessful reclosing back into a fault and subsequent clearing of the line. Circuit one of line 1–2 was faulted at the bus 1 end with a 3-phase to ground fault that is cleared in 4 cycles (5 cycles at the remote–bus 2). High-speed reclosing time is measure in cycles from the time the bus 1 end circuit breaker opens.**

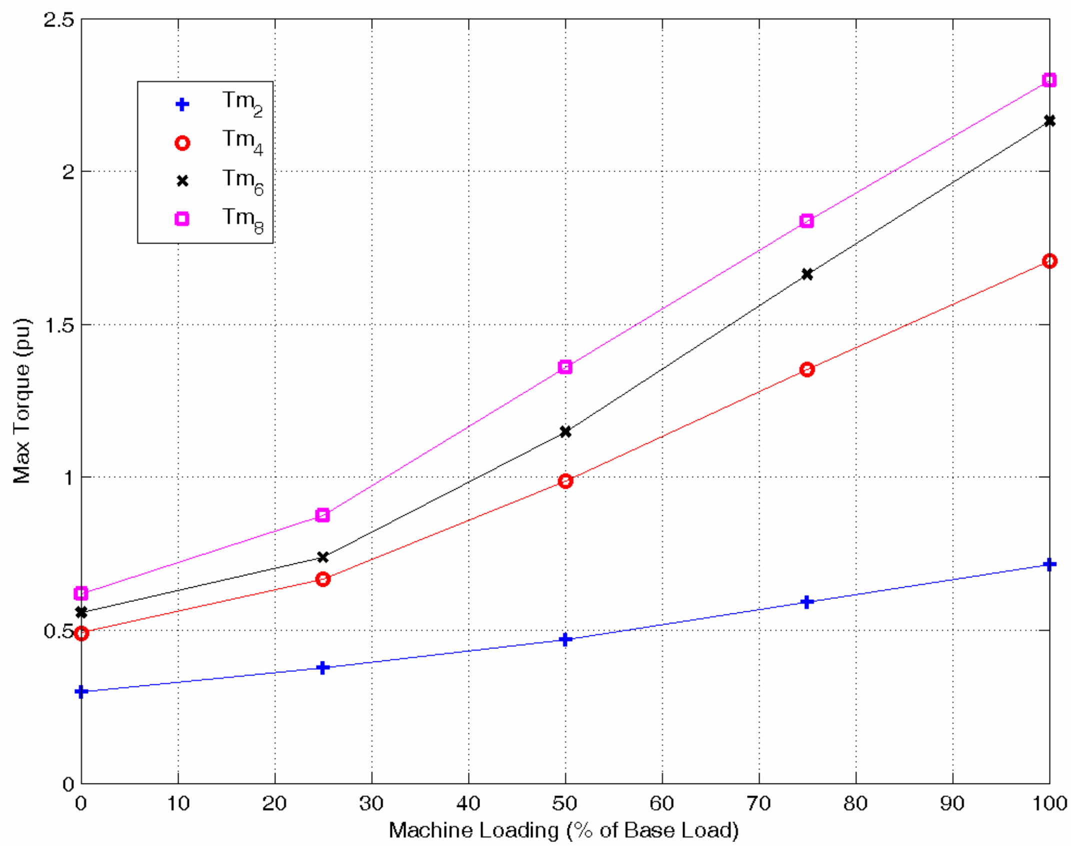
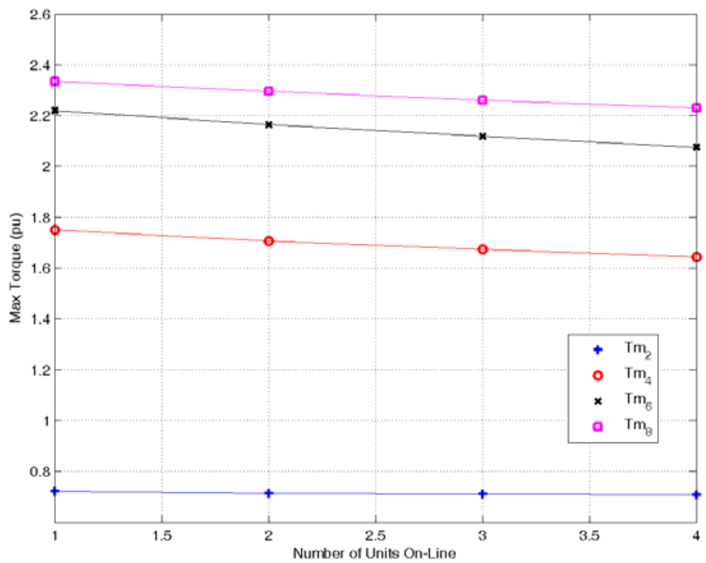
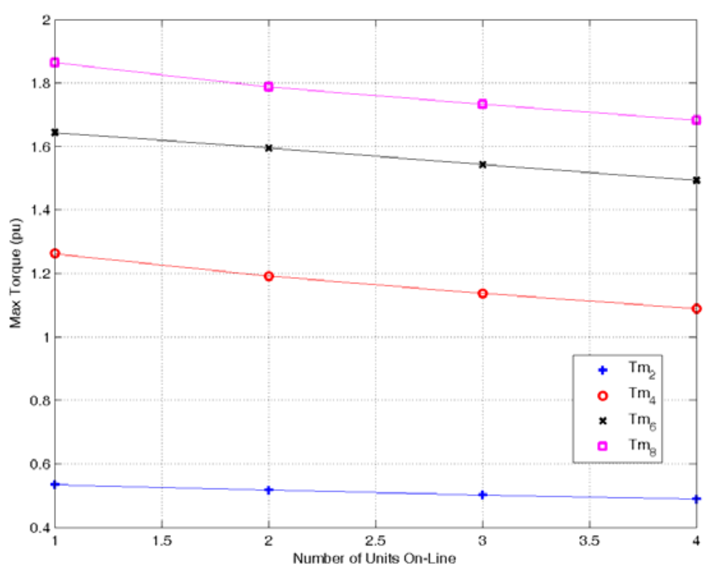



**Figure 4-11**
**Plot of peak torque (pu) on each relevant shaft segment for the 1,800-RPM machine (SM1) for varying initial steady-state loading on the turbine-generator. Circuit one of line 1–2 was faulted at the bus 1 end with a 3-phase to ground fault that is cleared in 4 cycles (5 cycles at the remote–bus 2).**




**a) Fault at 0 miles from the plant.**




**b) Fault at 10 miles from the plant.**

**Figure 4-12**
**Plot of peak torque (pu) on each relevant shaft segment for the 1,800-RPM machine (SM1) for varying number of identical 1,800-RPM units on-line at bus 1. Circuit one of line 1–2 was faulted at the bus 1 end with a 3-phase to ground fault that is cleared in 4 cycles (5 cycles at the remote–bus 2).**

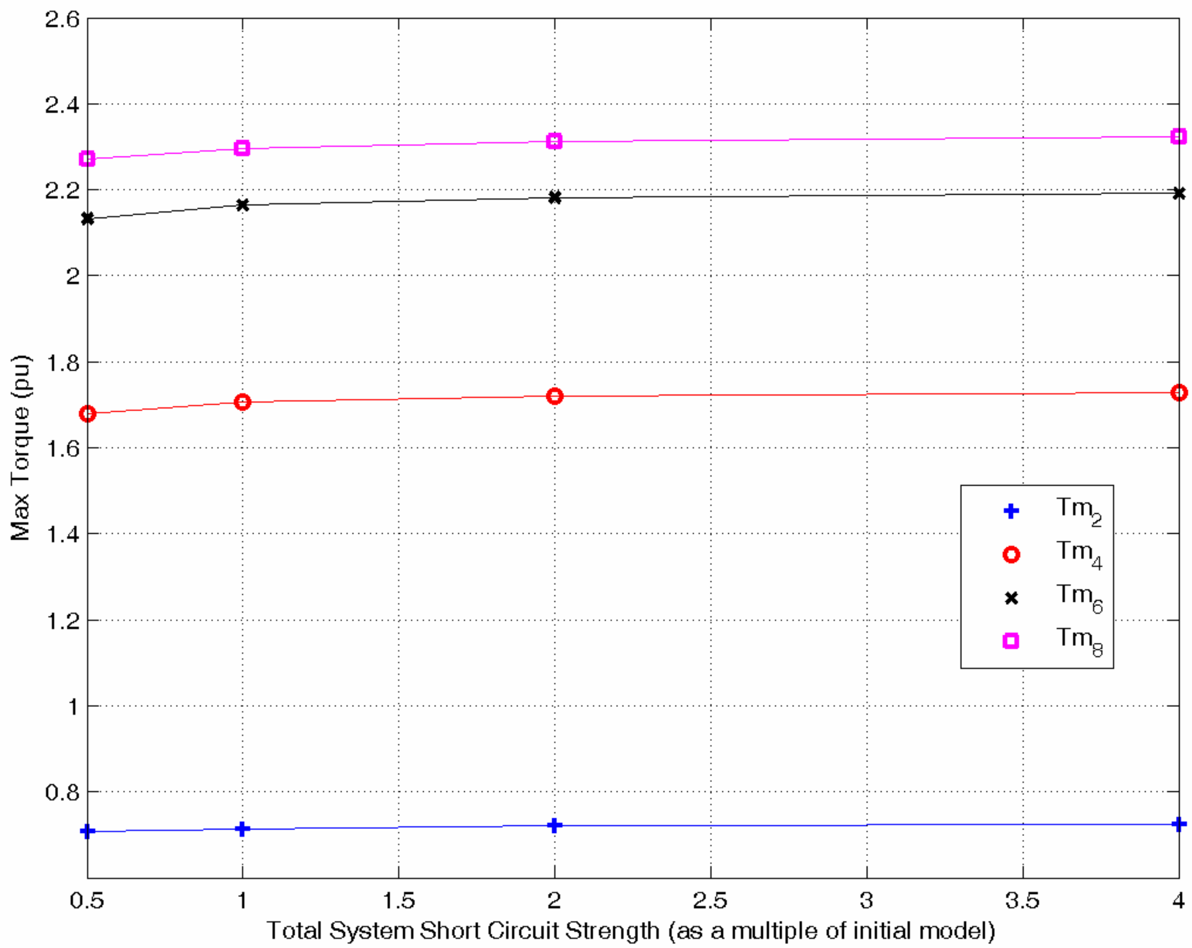



**Figure 4-13**
**Plot of peak torque (pu) on each relevant shaft segment for the 1,800-RPM machine (SM1) for varying total system short circuit strength—that is assuming that the interconnected power system is stronger. Circuit one of line 1–2 was faulted at the bus 1 end with a 3-phase to ground fault that is cleared in 4 cycles (5 cycles at the remote–bus 2).**

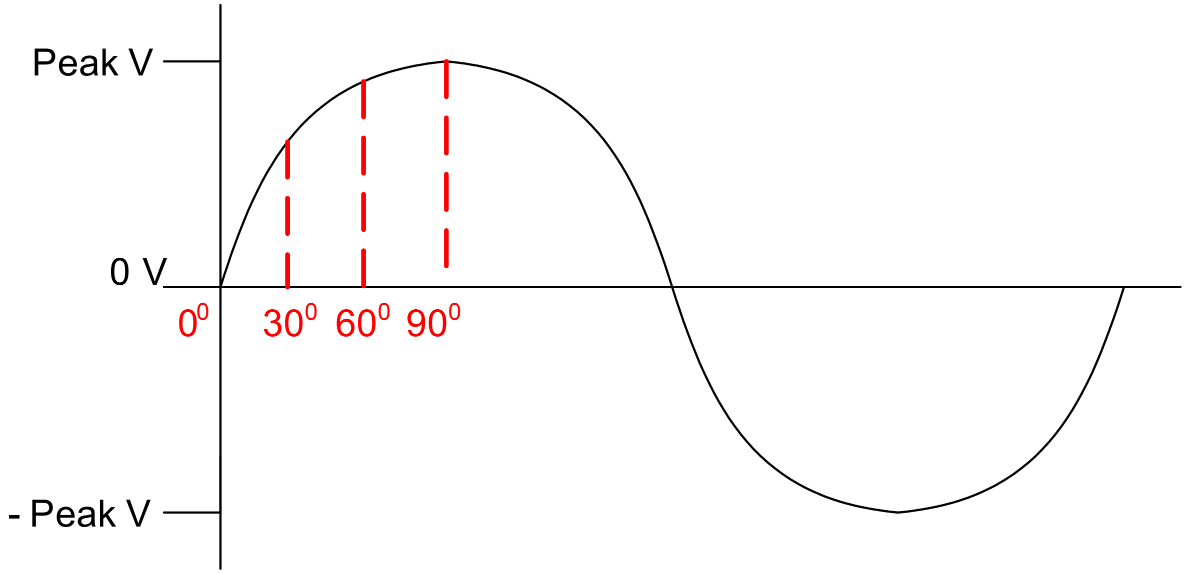



**Figure 4-14**
**Point on wave of fault inception.**

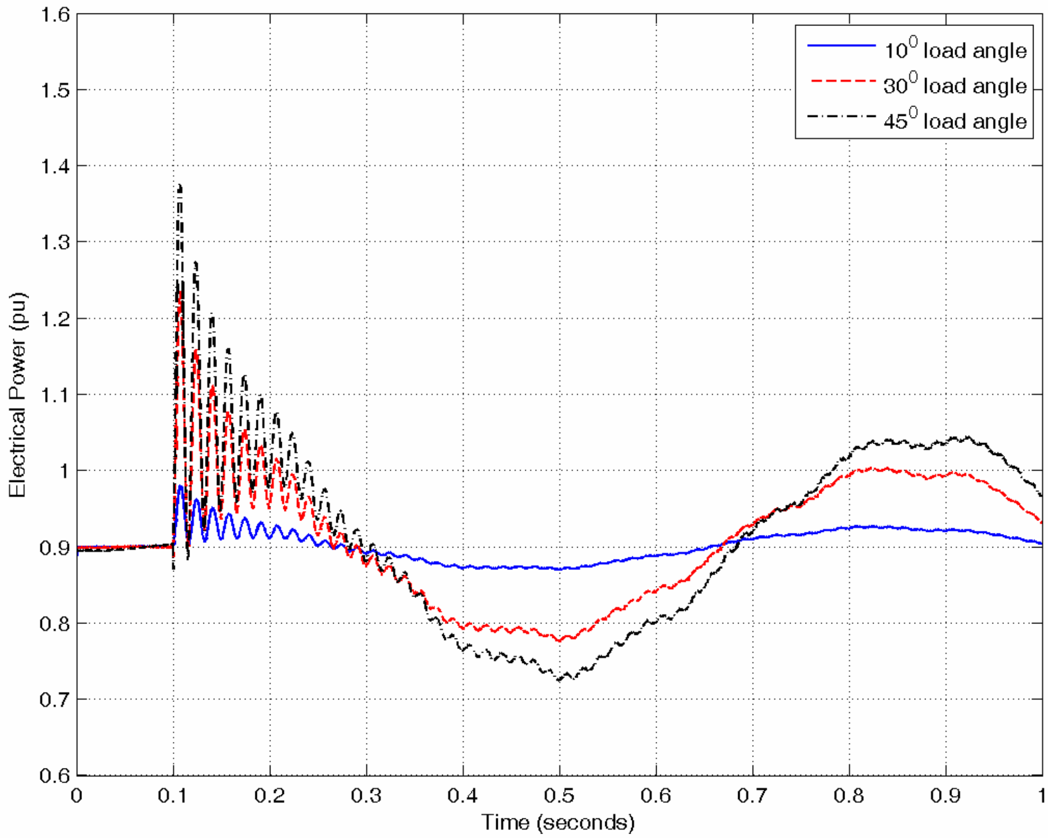



**Figure 4-15**
**Plot of electrical power transients (pu) on the generator due to reclosing of one circuit of line 1-2 (with the other circuit already out-of-service) with varying "load angle" across the closing breaker. When manually (by operator action) reclosing a transmission line (re-insert into the system), there will be a phase angle difference between the system voltage on the opposite sides of the circuit breaker that is used to completely re-insert the line into the transmission system. This phase angle difference (referred to here as the "load angle") is determined by power flow in adjacent paths on the transmission network and is an indication of the initial transient inrush of power into the line once it is re-inserted into the network.**

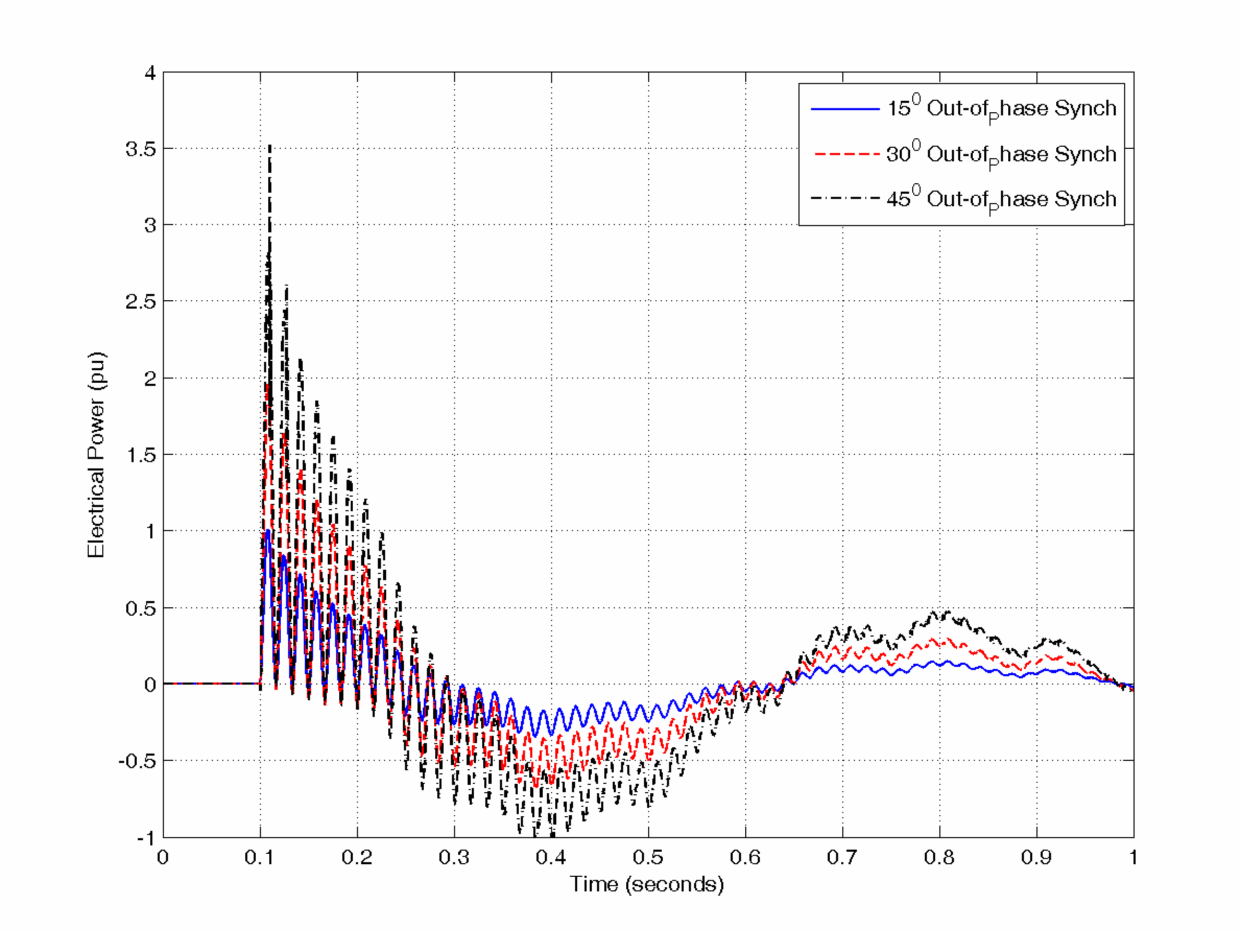



**Figure 4-16**
**Plot of electrical power transient (pu) on the generator for the 1,800-RPM machine (SM1). Cases shown are for varying angles of out-of-phase synchronization of one of the two 1,800-RPM units.**

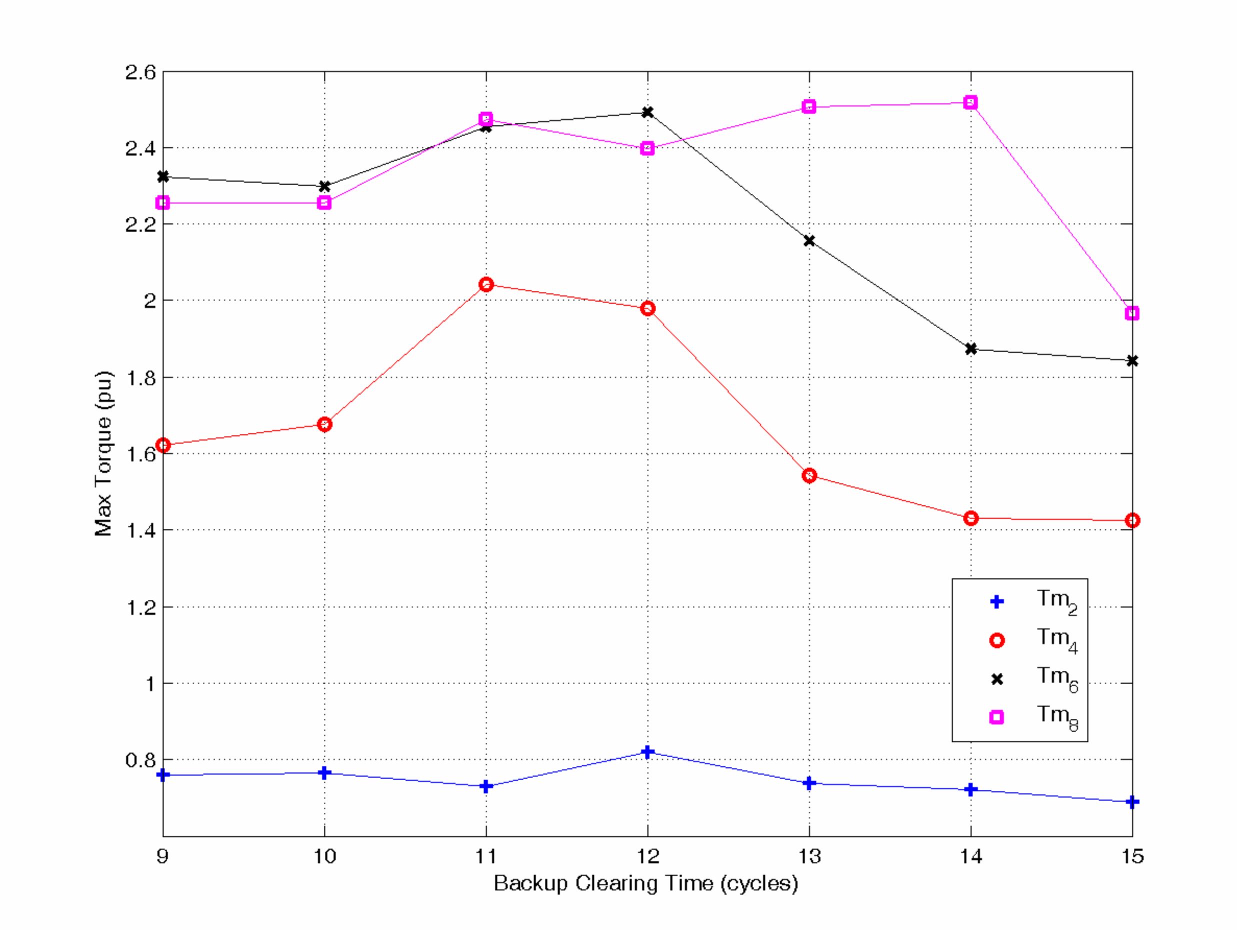



**Figure 4-17**
**Plot of peak torque (pu) on each relevant shaft segment for the 1,800-RPM machine (SM1) for varying back-up clearing time. Circuit one of line 1–2 was faulted at the bus 1 end with a 3-phase to ground fault. Then it was assumed that due to mechanically failure in the circuit breaker, one phase of the bus 1 end circuit breaker sticks (does not open) while the other two phases open in 4 cycles and the remote (bus 2) end breaker opens in 5 cycles. Due to the stuck breaker at bus 1, backup protection clears the circuit x cycles after fault initiation and also results in tripping the adjacent 1,500 MVA machine (SM2)—x is the backup clearing time plotted on the horizontal axis above.**

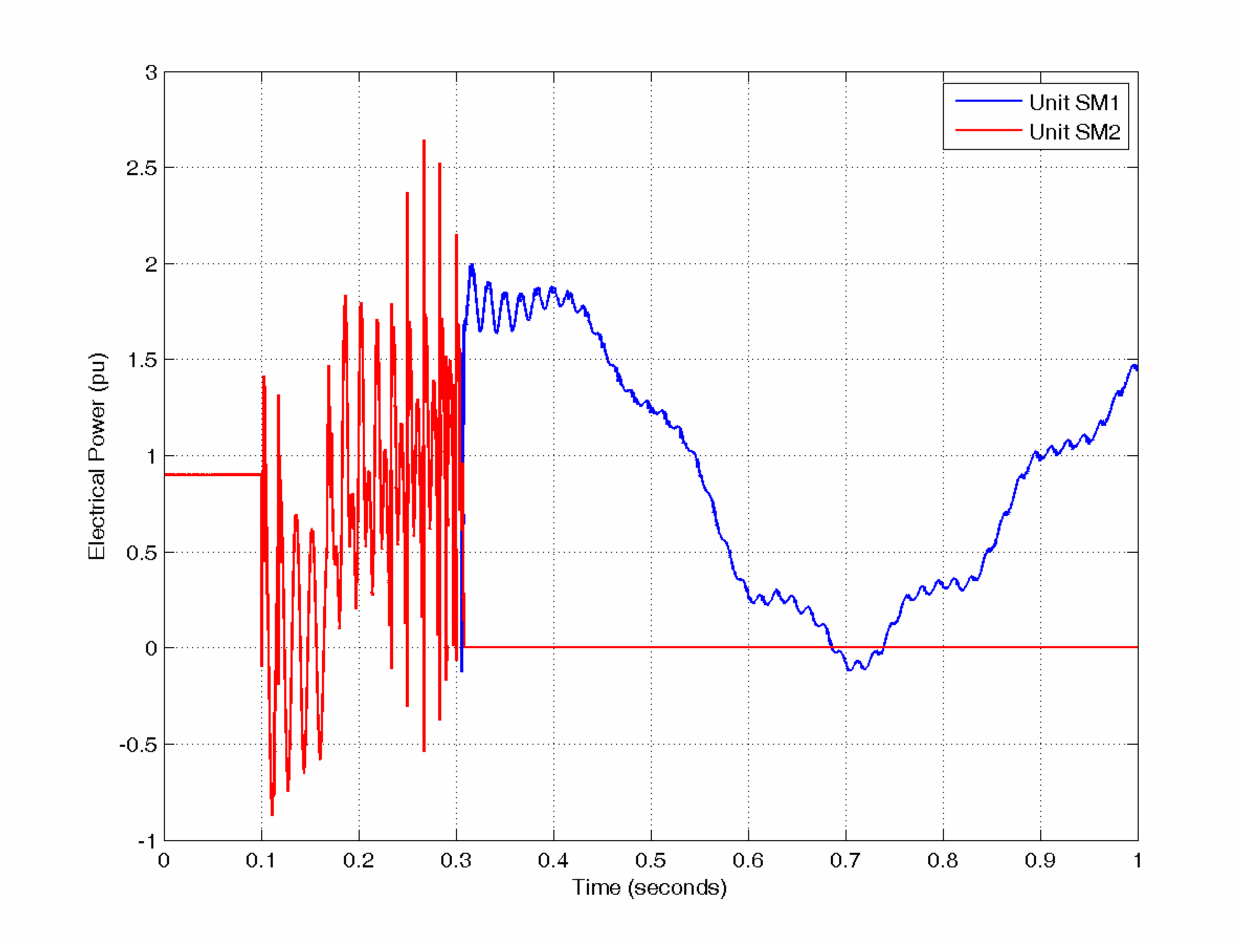



**Figure 4-18**
**Plot of electrical power transients on machines SM1 and SM2 (the two 1,800-RPM machines) for the case of back-up clearing time, after 12 cycles, of circuit one of line 1–2, with a fault at the bus 1 end (3-phase to ground fault). It was assumed that due to mechanically failure in the circuit breaker, one phase of the bus 1 end circuit breaker sticks (does not open) while the other two phases open in 4 cycles and the remote (bus 2) end breaker opens in 5 cycles. Due to the stuck breaker at bus 1, backup protection clears the circuit 12 cycles after fault initiation and also results in tripping the adjacent 1,500 MVA machine (SM2).**

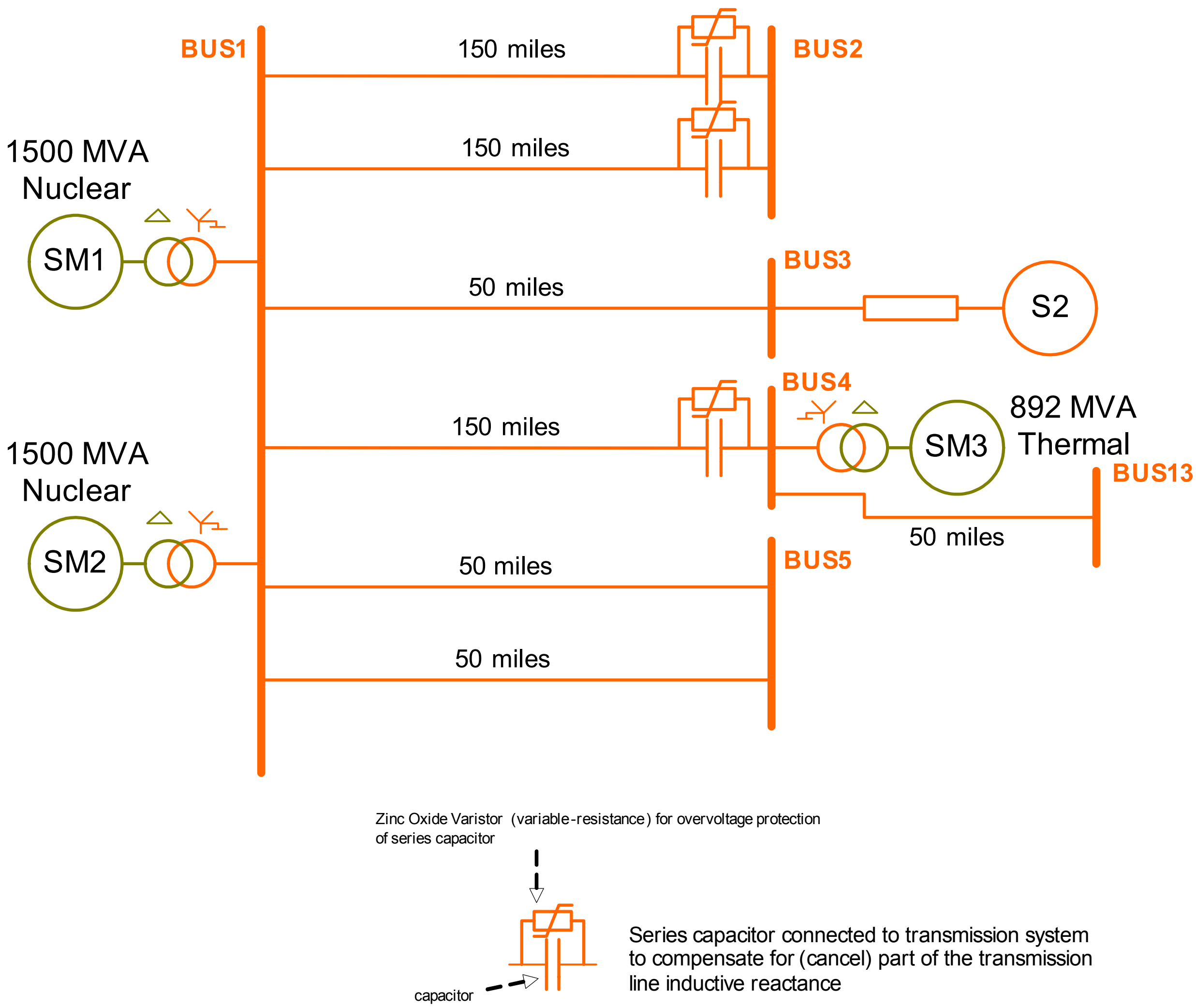
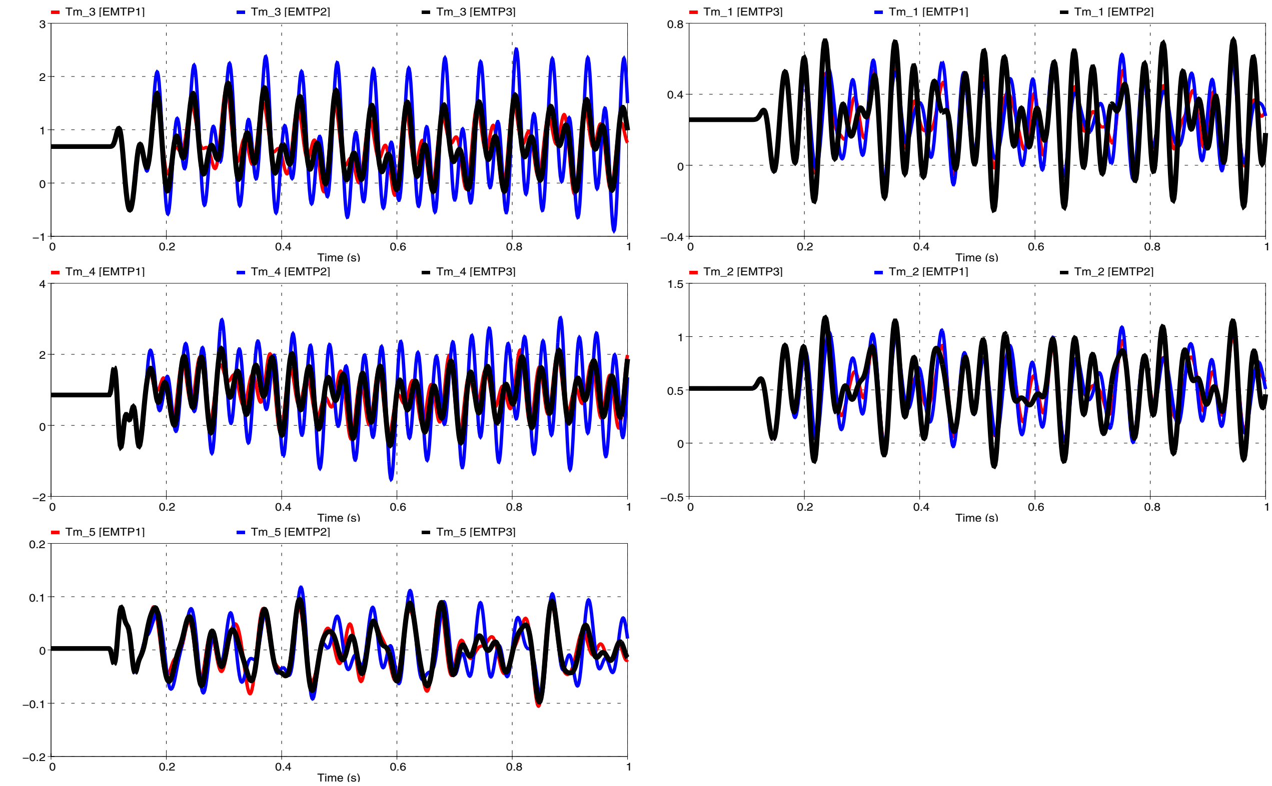



**Figure 4-19**
**System model showing locations of series capacitors for sensitivity runs associated with series capacitors. The rest of the system model is as depicted in Figure 4-1.**




[EMTP1] Case With Series Capacitor – Fast Bypass Protection
[EMTP2] Case With Series Capacitor – Zinc Oxide Protection only
[EMTP3] Without Series Capacitor

**Figure 4-20**
**Transient torques associated with the 3,600-RPM machine (SM3) for fault and tripping of line 4-13 with and without a series capacitor on line 1-4.**

## 4.7 The Zone of Vulnerability for the Sample System

The general approach in the determination of the ZoV for a turbine generator consists of varying the characteristics of the disturbance (location, type, distance, etc.) and comparing the peak torques at each shaft section to a certain threshold. This section shows the application of this approach for the two machines studied: the 1,800-RPM and 3,600-RPM machines.

The results of the parametric study are compared to the peak torque levels from generator terminal faults to suggest a ZoV for the two turbine generators represented. For the generators represented in this study, the simulations provided dramatically different conclusions: the 1,800-RPM turbine generator had much lower peak torque levels in per unit of its rating for terminal faults than the 3,600-RPM machine. However, there was not as much difference in peak torque levels between the two machines for faults in the transmission system. This being the case, there are a significant number of transmission system faults in Table 4-1 where the peak shaft torques for the 1,800-RPM machine exceeds the peak torque on the corresponding shaft for a terminal short circuit. On the other hand, again, given the characteristics of the 3,600-RPM machine studied, there are no faults (other than one fault with series capacitor compensation and some of the unsuccessful HSR events) where the peak torque on any shaft of the 3,600-RPM machine reaches or exceeds the peak torque on the corresponding shaft for terminal faults.

An investigation into the reasons for the differences between the responses of the two machines to terminal faults showed that the primary reason was the difference in transient and subtransient reactances of the two machines. The direct axis subtransient reactance for the 3,600-RPM generator is 0.135 pu on its 892.4 MVA base while the direct axis subtransient reactance for the 1,800-RPM machine is 0.28 pu on its 1,500 MVA base. This difference results in more than twice the per unit torque shock on the SM3 machine for a terminal fault. The unit transformer adds 0.18 pu reactance, which reduces the initial shock for faults on the transmission network. This reduction is more pronounced for the 3,600-RPM machine because the transformer reactance is a larger percentage of the total reactance. The step change in torque due to the change in power out of the machine when the fault occurs is nearly the same for faults on the generator terminals and faults on the high-side of the transformer so the 60 and 120 Hz transient components of the fault torque account for much of the difference in response. A second factor in the response is the turbine generator inertia, which is larger for the 1,800-RPM turbine generator (3.75 MWs/MVA) than for the 3,600-RPM unit (2.89 MWs/MVA). This reduces the effect of the higher frequency components of transient torque for the higher inertia machine.

These differences in response to terminal faults may result in a more conservative assessment of the ZoV for the 1,800-RPM turbine generator when the terminal faults are used as the basis of comparison. If S-N curves (curves showing the number of stress cycles as a function of stress amplitude before crack initiation) were available for each of the major shaft sections, a more precise assessment could be made. This assessment might also require an estimate of the number of transients that might occur with resulting stress above the endurance limit (the stress level where the shaft can withstand a nearly infinite number of stress cycles).

The rest of this discussion deals with defining the ZoV for the 1,800 RPM machine. This approach is to be treated as the generic approach for defining the ZoV for any machine.

### 4.7.1 Defining the ZoV

The study results for the 1,800-RPM machine would define faults that were on any of the transmission lines connected to the plant to be inside the ZoV. The contour of the ZoV will be defined by the maximum distance from the plant on each transmission line where the peak torque on at least one shaft segment exceeds the peak torque for a terminal short circuit. Typically one would define one ZoV for 3-phase faults, one for 2-phase, and one for single phase faults. Alternatively one can combine the 3-phase and 2-phase faults together, as "multiphase" ZoV, and one ZoV for single phase faults.

For the multiphase faults, as the study has shown, the resulting torques are higher than the ones for single phase faults, but they are less frequent. The study has also shown that some single phase to ground faults on the high voltage bus at the plant had peak shaft transient torques on the LP1-LP2 and LP2-LP3 shafts that exceeded the peak torque for a terminal fault. Given that the single phase faults are much more common (over 80% ), they are very important to consider because over the life of the plant there could be a significant number of faults that could add fatigue damage to the unit, and hence one needs to consider the ZoV defined by them.

### 4.7.2 Need to Consult Turbine Generator Manufacturer

A completely different conclusion might be drawn for the 3,600 RPM machine. Table 4-1 shows no system faults with peak torque levels above those for the terminal short circuit. However, the extremely high torque levels for the terminal fault (3.38 pu on the MVA base of the machine is roughly equal to 4 times the normal load torque) raise concern that the criteria considered in this study may not be conservative enough to assure that there is no fatigue damage for the system faults. Since this result for this specific machine were due to abnormally low values of transient and subtransient reactances for the generator they should not be used to make general conclusions about the ability of other machines to withstand system disturbances (note: it is speculated that the reason for the apparently low sub-transient and transient reactance of this machine is that the generator may actually have been de-rated and applied to a smaller turbine). Instead such results should be used in discussion with the turbine generator manufacturer to better determine the strength of each of the major shafts and develop an S-N curve to help estimate fatigue life expenditure for the machine to assure that this machine is not damaged by events in the network.

Both of these turbine generator models disclosed a need to work with the manufacturer of the turbine generator to obtain information about the fatigue capability of the units.

### 4.7.3 Drawing the ZoV

In the absence of information from the turbine-generator manufacturer, the ZoV for different type of faults for a system can be obtained from simulations similar to the ones used in this study. For example, the ZoV for multiphase faults for the system used in this project includes the area encircled in Figure 4-21. The precise fault distance from the plant for the two 50 mile long transmission lines where the peak torsional response on all shafts drops below the terminal short circuit level is about 60 miles. The boundary beyond buses 2, 3, and 5 was not precisely determined, but is estimated to be about 10–20 miles (actual simulations will determine this precisely). (Data needed to draw this contour is partly contained in Figure 4-6, which is for 3-phase faults. Similar figures are needed for 2- phase and single phase faults, but were not derived for this study.)

Another ZoV can be drawn for single phase to ground faults. As stated before this is expected to be smaller than multiphase faults, and will be contained in the multiphase fault ZoV.

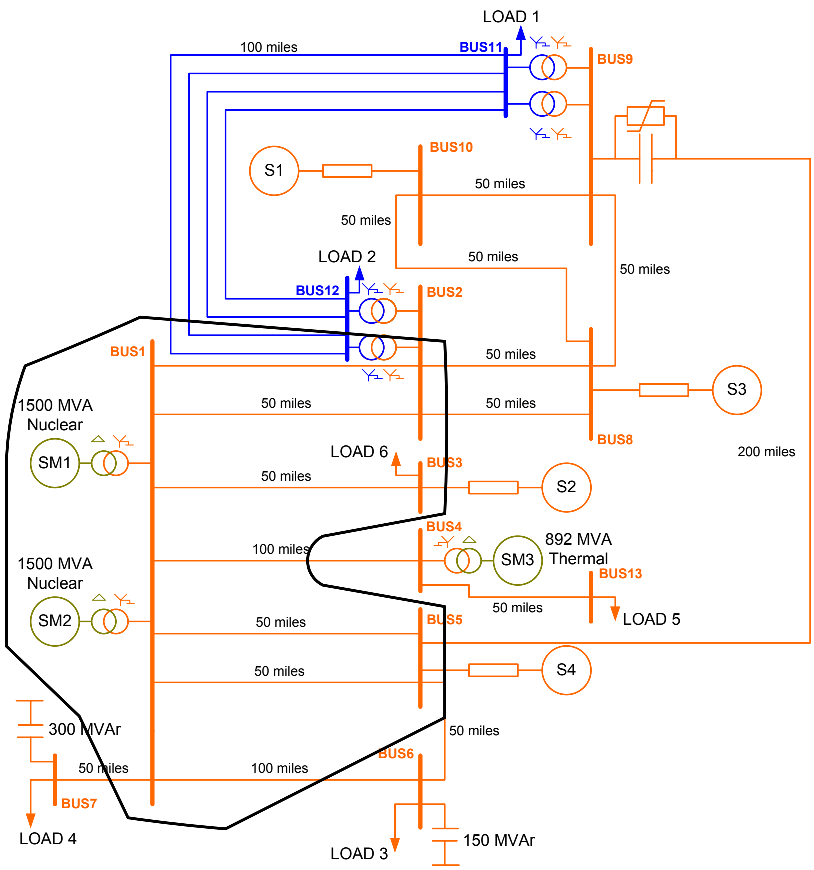



**Figure 4-21**
**System model with the 1800-RPM machine plant ZoV for "multiphase" faults in the transmission network shown. Not shown are the ZoV for single-phase faults as well as the ZoV for high speed reclosing.**

Finally, if high speed recolsing is used on lines close to the plant, then a separate ZoV may be drawn for high speed reclosing. It is important to keep this ZoV separate from the others. As stated before reclosing into a fault (unsuccessful reclosure) can be much more severe than applying two faults (separated considerably in time) at the same location. This associated ZoV may not be concentric with the plant if the lines emanating from the plant do not have high speed relcosing, as typically is the case. This is shown pictorially in Figure 1-1 as the non concentric ZoV contour.

### *4.7.4 Systematic Approach*

Based on the results of this project, the following methodology is proposed for determining the ZoV for a plant:

1. Develop a detailed 3-phase electrical model of the turbine-generator and include a lumped mass-spring model of the mechanical shaft that faithfully represents the key torsional modes. The generator excitation system may also be modeled. Modeling the turbine-governor controls is not necessary.
2. Developed a 3-phased model of the nearby electrical system, including explicit models of series capacitors and their overvoltage protection system.
3. Develop a list of all credible faults and switching phenomena on the lines emanating from the plant and up to two bus away, i.e.
   a. 3-phase to ground faults with normal line clearing
   b. 2-phase to ground faults with normal line clearing
   c. Single-line to ground faults with normal line clearing
   d. Any high-speed reclosing schemes or single-pole switching schemes on any of the lines out of the plant and up to two buses away.

To calibrate the analysis, start by simulating 3-phase to ground faults at the terminals (low voltage side of the generator step-up transformer). Thus, record the peak transient torque observed on each shaft segment. Now simulate all of the faults and switching events identified and then compare the observed peak transient torques on each shaft segment for the simulated network events with the peak transient torques determined for the generator terminal fault. Thus, the Zov may be defined as the region within which the peak transient torques from the network switching event is equal to or greater than the peak transient torque for the machine terminal fault (or to be more conservative one may select to define the boundary at say 75–80% of the peak torques for a machine terminal fault).

As stated earlier, the ZoV for high speed reclosing (HSR) should be drawn separate from normally cleared faults. The HSR ZoV is not concentric with the plant, and is removed (remote) from the plant since HSR is typically not exercised on lines emanating directly from the plant.

**Table 4-1**
**Peak mechanical torque on each shaft segment as a result of various system disturbances. Only the shaft segments that correspond to actual physical shafts with mechanical coupling are shown. Fault types are:**

**1g – single-line to ground fault**
**2g – two phase to ground fault**
**2ng – phase to phase fault, ungrounded**
**3g – three phase to ground fault**
**3ng – three phase ungrounded fault**

| Fault Type | Fault Location | Line Tripped | Peak Transient Torque (pu) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | SM1 | | | | SM3 | | | | |
| | | | Tm2 | Tm4 | Tm6 | Tm8 | Tm1 | Tm2 | Tm3 | Tm4 | Tm5 |
| 1g | SM1 terminals | N/A | 0.40 | 0.67 | 0.74 | 0.90 | 0.27 | 0.54 | 0.75 | 0.93 | 0.01 |
| 1g | SM3 terminals | N/A | 0.23 | 0.48 | 0.71 | 0.93 | 0.36 | 0.67 | 0.79 | 0.86 | 0.06 |
| 2g | SM1 terminals | N/A | 0.36 | 0.59 | 0.82 | 1.07 | 0.29 | 0.58 | 0.89 | 1.09 | 0.01 |
| 2g | SM3 terminals | N/A | 0.26 | 0.55 | 0.80 | 1.01 | 0.42 | 0.79 | 1.05 | 1.29 | 0.11 |
| 2ng | SM1 terminals | N/A | 0.36 | 0.59 | 0.82 | 1.07 | 0.29 | 0.58 | 0.89 | 1.09 | 0.01 |
| 2ng | SM3 terminals | N/A | 0.26 | 0.55 | 0.80 | 1.01 | 0.42 | 0.79 | 1.06 | 1.29 | 0.11 |
| 3g | SM1 terminals | N/A | **0.62** | **0.77** | **1.01** | **1.57** | 0.31 | 0.59 | 0.96 | 1.25 | 0.02 |
| 3g | SM3 terminals | N/A | 0.27 | 0.58 | 0.85 | 1.05 | **0.84** | **1.42** | **2.37** | **3.38** | **0.22** |
| 3ng | SM1 terminals | N/A | 0.62 | 0.77 | 1.01 | 1.57 | 0.31 | 0.59 | 0.96 | 1.25 | 0.02 |
| 3ng | SM3 terminals | N/A | 0.27 | 0.58 | 0.85 | 1.05 | 0.84 | 1.42 | 2.37 | 3.38 | 0.22 |
| 1g | Bus 1 end | Line 1 - 2 | 0.37 | 0.82 | 1.07 | 1.30 | 0.30 | 0.58 | 0.78 | 1.01 | 0.01 |
| 1g | Bus 2 end | Line 1 - 2 | 0.25 | 0.51 | 0.75 | 0.97 | 0.26 | 0.52 | 0.70 | 0.89 | 0.01 |
| 2g | Bus 1 end | Line 1 - 2 | 0.51 | 1.23 | 1.41 | 1.67 | 0.37 | 0.69 | 1.08 | 1.32 | 0.03 |
| 2g | Bus 2 end | Line 1 - 2 | 0.31 | 0.68 | 0.96 | 1.16 | 0.28 | 0.55 | 0.78 | 1.00 | 0.01 |
| 2ng | Bus 1 end | Line 1 - 2 | 0.44 | 1.08 | 1.28 | 1.50 | 0.34 | 0.64 | 0.97 | 1.22 | 0.02 |
| 2ng | Bus 2 end | Line 1 - 2 | 0.30 | 0.65 | 0.93 | 1.13 | 0.28 | 0.55 | 0.76 | 0.97 | 0.01 |
| 3g | Bus 1 end | Line 1 - 2 | 0.66 | 1.67 | 1.75 | 2.06 | 0.46 | 0.83 | 1.45 | 1.68 | 0.05 |

| Fault Type | Fault Location | Line Tripped | Peak Transient Torque (pu) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | SM1 | | | | SM3 | | | | |
| | | | Tm2 | Tm4 | Tm6 | Tm8 | Tm1 | Tm2 | Tm3 | Tm4 | Tm5 |
| 3g | Bus 2 end | Line 1 - 2 | 0.40 | 0.89 | 1.21 | 1.43 | 0.32 | 0.61 | 0.92 | 1.15 | 0.03 |
| 3ng | Bus 1 end | Line 1 - 2 | 0.65 | 1.68 | 1.77 | 2.05 | 0.46 | 0.84 | 1.49 | 1.71 | 0.06 |
| 3ng | Bus 2 end | Line 1 - 2 | 0.40 | 0.89 | 1.21 | 1.43 | 0.32 | 0.61 | 0.92 | 1.15 | 0.03 |
| 1g | Bus 1 end | Line 1 - 3 | 0.37 | 0.81 | 1.06 | 1.29 | 0.30 | 0.58 | 0.77 | 1.01 | 0.02 |
| 1g | Bus 3 end | Line 1 - 3 | 0.24 | 0.50 | 0.75 | 0.96 | 0.26 | 0.53 | 0.72 | 0.90 | 0.01 |
| 2g | Bus 1 end | Line 1 - 3 | 0.52 | 1.23 | 1.38 | 1.65 | 0.37 | 0.70 | 1.07 | 1.32 | 0.03 |
| 2g | Bus 3 end | Line 1 - 3 | 0.29 | 0.61 | 0.89 | 1.08 | 0.28 | 0.55 | 0.75 | 0.97 | 0.01 |
| 2ng | Bus 1 end | Line 1 - 3 | 0.44 | 1.08 | 1.24 | 1.48 | 0.34 | 0.65 | 0.98 | 1.22 | 0.02 |
| 2ng | Bus 3 end | Line 1 - 3 | 0.28 | 0.59 | 0.86 | 1.05 | 0.28 | 0.54 | 0.74 | 0.96 | 0.01 |
| 3g | Bus 1 end | Line 1 - 3 | 0.66 | 1.68 | 1.73 | 2.02 | 0.46 | 0.84 | 1.46 | 1.69 | 0.05 |
| 3g | Bus 3 end | Line 1 - 3 | 0.35 | 0.75 | 1.06 | 1.25 | 0.30 | 0.58 | 0.80 | 1.06 | 0.02 |
| 3ng | Bus 1 end | Line 1 - 3 | 0.66 | 1.70 | 1.76 | 2.01 | 0.47 | 0.85 | 1.50 | 1.73 | 0.06 |
| 3ng | Bus 3 end | Line 1 - 3 | 0.35 | 0.75 | 1.07 | 1.26 | 0.30 | 0.58 | 0.81 | 1.06 | 0.02 |
| 1g | Bus 1 end | Line 1 - 5 | 0.36 | 0.81 | 1.06 | 1.29 | 0.30 | 0.58 | 0.78 | 1.01 | 0.01 |
| 1g | Bus 5 end | Line 1 - 5 | 0.27 | 0.56 | 0.81 | 1.03 | 0.27 | 0.53 | 0.72 | 0.91 | 0.01 |
| 2g | Bus 1 end | Line 1 - 5 | 0.51 | 1.21 | 1.41 | 1.66 | 0.36 | 0.68 | 1.06 | 1.31 | 0.03 |
| 2g | Bus 5 end | Line 1 - 5 | 0.35 | 0.75 | 1.03 | 1.24 | 0.29 | 0.57 | 0.82 | 1.02 | 0.01 |
| 2ng | Bus 1 end | Line 1 - 5 | 0.43 | 1.07 | 1.27 | 1.49 | 0.33 | 0.64 | 0.96 | 1.21 | 0.02 |
| 2ng | Bus 5 end | Line 1 - 5 | 0.32 | 0.70 | 0.98 | 1.17 | 0.28 | 0.56 | 0.79 | 0.99 | 0.01 |
| 3g | Bus 1 end | Line 1 - 5 | 0.65 | 1.65 | 1.75 | 2.04 | 0.45 | 0.82 | 1.43 | 1.66 | 0.05 |
| 3g | Bus 5 end | Line 1 - 5 | 0.45 | 1.01 | 1.32 | 1.55 | 0.33 | 0.64 | 0.99 | 1.20 | 0.03 |
| 3ng | Bus 1 end | Line 1 - 5 | 0.65 | 1.67 | 1.77 | 2.04 | 0.46 | 0.83 | 1.47 | 1.70 | 0.06 |
| 3ng | Bus 5 end | Line 1 - 5 | 0.45 | 1.01 | 1.33 | 1.55 | 0.33 | 0.64 | 1.00 | 1.21 | 0.03 |
| 1g | Bus 1 end | Line 1 - 6 | 0.37 | 0.81 | 1.06 | 1.29 | 0.30 | 0.58 | 0.77 | 1.01 | 0.01 |
| 1g | Bus 6 end | Line 1 - 6 | 0.24 | 0.47 | 0.71 | 0.93 | 0.26 | 0.52 | 0.70 | 0.87 | 0.00 |
| 2g | Bus 1 end | Line 1 - 6 | 0.51 | 1.23 | 1.40 | 1.66 | 0.37 | 0.69 | 1.07 | 1.32 | 0.03 |
| 2g | Bus 6 end | Line 1 - 6 | 0.27 | 0.56 | 0.82 | 1.03 | 0.27 | 0.54 | 0.74 | 0.93 | 0.01 |
| 2ng | Bus 1 end | Line 1 - 6 | 0.44 | 1.08 | 1.26 | 1.49 | 0.34 | 0.64 | 0.97 | 1.22 | 0.02 |
| 2ng | Bus 6 end | Line 1 - 6 | 0.27 | 0.55 | 0.81 | 1.02 | 0.27 | 0.53 | 0.73 | 0.92 | 0.01 |
| 3g | Bus 1 end | Line 1 - 6 | 0.66 | 1.68 | 1.74 | 2.03 | 0.46 | 0.83 | 1.45 | 1.68 | 0.05 |

| Fault Type | Fault Location | Line Tripped | Peak Transient Torque (pu) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | SM1 | | | | SM3 | | | | |
| | | | Tm2 | Tm4 | Tm6 | Tm8 | Tm1 | Tm2 | Tm3 | Tm4 | Tm5 |
| 3g | Bus 6 end | Line 1 - 6 | 0.33 | 0.69 | 0.98 | 1.19 | 0.29 | 0.57 | 0.82 | 1.03 | 0.02 |
| 3ng | Bus 1 end | Line 1 - 6 | 0.65 | 1.70 | 1.77 | 2.04 | 0.46 | 0.84 | 1.49 | 1.72 | 0.06 |
| 3ng | Bus 6 end | Line 1 - 6 | 0.32 | 0.68 | 0.96 | 1.18 | 0.29 | 0.57 | 0.82 | 1.02 | 0.02 |
| 1g | Bus 1 end | Line 1 - 7 | 0.36 | 0.76 | 1.02 | 1.24 | 0.29 | 0.58 | 0.76 | 0.99 | 0.02 |
| 2g | Bus 1 end | Line 1 - 7 | 0.51 | 1.20 | 1.35 | 1.61 | 0.36 | 0.69 | 1.05 | 1.31 | 0.03 |
| 3g | Bus 1 end | Line 1 - 7 | 0.66 | 1.67 | 1.73 | 2.00 | 0.46 | 0.83 | 1.44 | 1.68 | 0.05 |
| 1g | Bus 4 end | Line 4 - 13 | 0.25 | 0.49 | 0.74 | 0.96 | 0.34 | 0.67 | 0.93 | 1.16 | 0.04 |
| 1g | Bus 13 end | Line 4 - 13 | 0.24 | 0.47 | 0.72 | 0.95 | 0.31 | 0.63 | 0.91 | 1.18 | 0.03 |
| 2g | Bus 4 end | Line 4 - 13 | 0.26 | 0.53 | 0.77 | 0.98 | 0.44 | 0.81 | 1.21 | 1.58 | 0.05 |
| 2g | Bus 13 end | Line 4 - 13 | 0.24 | 0.49 | 0.74 | 0.96 | 0.34 | 0.64 | 0.96 | 1.31 | 0.04 |
| 2ng | Bus 4 end | Line 4 - 13 | 0.25 | 0.51 | 0.75 | 0.97 | 0.37 | 0.71 | 0.99 | 1.36 | 0.03 |
| 2ng | Bus 13 end | Line 4 - 13 | 0.24 | 0.49 | 0.74 | 0.96 | 0.33 | 0.64 | 0.95 | 1.27 | 0.04 |
| 3g | Bus 4 end | Line 4 - 13 | 0.28 | 0.57 | 0.81 | 1.01 | 0.57 | 1.02 | 1.88 | 2.17 | 0.10 |
| 3g | Bus 13 end | Line 4 - 13 | 0.26 | 0.53 | 0.78 | 0.99 | 0.41 | 0.76 | 1.22 | 1.63 | 0.08 |
| 3ng | Bus 4 end | Line 4 - 13 | 0.28 | 0.57 | 0.81 | 1.02 | 0.58 | 1.03 | 1.94 | 2.22 | 0.10 |
| 3ng | Bus 13 end | Line 4 - 13 | 0.24 | 0.49 | 0.74 | 0.96 | 0.33 | 0.64 | 0.95 | 1.27 | 0.04 |
| 1g | Bus 5 end | Line 5 - 9 | 0.28 | 0.58 | 0.82 | 1.04 | 0.27 | 0.54 | 0.73 | 0.92 | 0.01 |
| 1g | Bus 9 end | Line 5 - 9 | 0.23 | 0.46 | 0.69 | 0.92 | 0.26 | 0.52 | 0.69 | 0.86 | 0.00 |
| 2g | Bus 5 end | Line 5 - 9 | 0.36 | 0.80 | 1.00 | 1.24 | 0.31 | 0.60 | 0.86 | 1.07 | 0.01 |
| 2g | Bus 9 end | Line 5 - 9 | 0.24 | 0.50 | 0.72 | 0.94 | 0.26 | 0.52 | 0.71 | 0.89 | 0.01 |
| 2ng | Bus 5 end | Line 5 - 9 | 0.34 | 0.75 | 0.96 | 1.18 | 0.30 | 0.58 | 0.83 | 1.04 | 0.01 |
| 2ng | Bus 9 end | Line 5 - 9 | 0.24 | 0.49 | 0.72 | 0.94 | 0.27 | 0.53 | 0.72 | 0.89 | 0.01 |
| 3g | Bus 5 end | Line 5 - 9 | 0.46 | 1.09 | 1.27 | 1.51 | 0.36 | 0.68 | 1.07 | 1.28 | 0.03 |
| 3g | Bus 9 end | Line 5 - 9 | 0.25 | 0.53 | 0.76 | 0.98 | 0.27 | 0.53 | 0.75 | 0.92 | 0.01 |
| 3ng | Bus 5 end | Line 5 - 9 | 0.46 | 1.10 | 1.28 | 1.51 | 0.36 | 0.68 | 1.08 | 1.29 | 0.03 |
| 3ng | Bus 9 end | Line 5 - 9 | 0.25 | 0.55 | 0.78 | 0.98 | 0.28 | 0.55 | 0.75 | 0.94 | 0.01 |
| 1g | Bus 9 end | Line 10 - 9 | 0.23 | 0.47 | 0.70 | 0.92 | 0.26 | 0.52 | 0.69 | 0.87 | 0.00 |
| 1g | Bus 10 end | Line 10 - 9 | 0.23 | 0.47 | 0.70 | 0.92 | 0.26 | 0.52 | 0.70 | 0.87 | 0.00 |
| 2g | Bus 9 end | Line 10 - 9 | 0.24 | 0.50 | 0.73 | 0.95 | 0.26 | 0.52 | 0.71 | 0.88 | 0.00 |
| 2g | Bus 10 end | Line 10 - 9 | 0.24 | 0.49 | 0.72 | 0.95 | 0.26 | 0.52 | 0.70 | 0.88 | 0.00 |

| Fault Type | Fault Location | Line Tripped | Peak Transient Torque (pu) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | SM1 | | | | SM3 | | | | |
| | | | Tm2 | Tm4 | Tm6 | Tm8 | Tm1 | Tm2 | Tm3 | Tm4 | Tm5 |
| 2ng | Bus 9 end | Line 10 - 9 | 0.24 | 0.49 | 0.73 | 0.94 | 0.26 | 0.52 | 0.71 | 0.88 | 0.00 |
| 2ng | Bus 10 end | Line 10 - 9 | 0.24 | 0.49 | 0.72 | 0.95 | 0.26 | 0.52 | 0.70 | 0.88 | 0.00 |
| 3g | Bus 9 end | Line 10 - 9 | 0.25 | 0.53 | 0.77 | 0.99 | 0.27 | 0.53 | 0.74 | 0.91 | 0.01 |
| 3g | Bus 10 end | Line 10 - 9 | 0.25 | 0.52 | 0.75 | 0.99 | 0.27 | 0.53 | 0.72 | 0.90 | 0.01 |
| 3ng | Bus 9 end | Line 10 - 9 | 0.25 | 0.53 | 0.77 | 0.99 | 0.27 | 0.53 | 0.74 | 0.91 | 0.01 |
| 3ng | Bus 10 end | Line 10 - 9 | 0.25 | 0.52 | 0.76 | 0.99 | 0.27 | 0.53 | 0.72 | 0.90 | 0.01 |
| 1g | Bus 11 end | Line 11 - 12 | 0.23 | 0.47 | 0.70 | 0.92 | 0.26 | 0.52 | 0.69 | 0.86 | 0.00 |
| 1g | Bus 12 end | Line 11 - 12 | 0.25 | 0.50 | 0.73 | 0.96 | 0.26 | 0.52 | 0.70 | 0.88 | 0.00 |
| 2g | Bus 11 end | Line 11 - 12 | 0.24 | 0.50 | 0.73 | 0.95 | 0.26 | 0.52 | 0.70 | 0.88 | 0.00 |
| 2g | Bus 12 end | Line 11 - 12 | 0.28 | 0.59 | 0.81 | 1.04 | 0.28 | 0.55 | 0.75 | 0.94 | 0.01 |
| 2ng | Bus 11 end | Line 11 - 12 | 0.24 | 0.49 | 0.72 | 0.94 | 0.26 | 0.52 | 0.70 | 0.88 | 0.00 |
| 2ng | Bus 12 end | Line 11 - 12 | 0.27 | 0.57 | 0.79 | 1.02 | 0.27 | 0.54 | 0.74 | 0.93 | 0.01 |
| 3g | Bus 11 end | Line 11 - 12 | 0.25 | 0.53 | 0.76 | 0.98 | 0.27 | 0.53 | 0.72 | 0.90 | 0.01 |
| 3g | Bus 12 end | Line 11 - 12 | 0.32 | 0.69 | 0.90 | 1.13 | 0.29 | 0.57 | 0.83 | 1.02 | 0.01 |
| 3ng | Bus 11 end | Line 11 - 12 | 0.25 | 0.53 | 0.77 | 0.98 | 0.27 | 0.53 | 0.72 | 0.90 | 0.01 |
| 3ng | Bus 12 end | Line 11 - 12 | 0.32 | 0.70 | 0.90 | 1.14 | 0.30 | 0.58 | 0.83 | 1.02 | 0.01 |
| | | **Maximum** | **0.66** | **1.70** | **1.77** | **2.06** | **1.00** | **1.42** | **2.37** | **3.38** | **0.97** |

# 5 CONCLUSIONS AND RECOMMENDATIONS

This report examined the zone of vulnerability (ZoV) for torsional fatigue due to faults and transmission line switching operations in the network connected to a generating plant. This subject received renewed interest when torsional cracks were discovered in two generator rotors at a nuclear plant in 2004. The subject had been studied in the 1970s and 1980s with the general conclusion that plants should not experience fatigue damage unless there was automatic high-speed reclosing (HSR) on the lines connected to the plants high voltage bus or there were other special circumstances. These special circumstances were series capacitor compensation, large loads like arc furnaces or drag lines that imposed repeated shocks on the plant and dynamic controllers like HVDC terminals, FACTS devices, large variable speed drives or powerful excitation controllers that could drive torsional oscillation at one of the lower torsional natural frequencies of the turbine generator shaft system. The plant that experienced the torsional cracks did not have any of the special circumstances and had not (to the operators knowledge) experienced an unusual number of faults or other system transients.

A study of the effects of grid disturbances on turbine-generators requires the gathering and sharing of event data between transmission system planners, operators and the power plant staff. EPRI has found that such exchange of important information is more prevalent outside the USA at utilities that are still vertically integrated. In the USA, de-regulation of the electric power business has reduced access to such information by the different parties. This has made it more difficult for the plants to obtain records of disturbances in the network and perform collaborative analyses with system planning staff to correlate plant information with network events.

In this study a thorough sensitivity analysis was conducted of various switching event in and around a network with two simulated power plants: one incorporating a large 1,800 RPM steam turbine-generator and another incorporating a large 3,600 RPM steam turbine-generator. Based on this analysis conclusions and recommendations can be drawn about the zone of vulnerability around a power plant within which network switching events are likely to cause significant loss of fatigue life and thus require detailed analysis. These conclusions are summarized in Table 5-1 and Figure 5-1. Figure 5-1 gives a diagrammatic representation of factors that influence the risk of torsional interactions. For example, the first item shown is “Increasing Fault Distance”. A bar is drawn next to this indicating a “high” level of “decreasing risk of torsional interaction. What this means is that as the fault distance increases, so to the risk of torsional interaction drops dramatically. The next item indicates that the fault clearing time can have a significant impact on increasing the risk of torsional interaction—as explain in Section 4, if the clearing time corresponds to an odd multiple of half cycles of a critical torsional mode, it can result in further magnifying the subsequent torsional response. Figure 5-2 may be used in conjunction with Figure 5-1—it shows other known cause of increasing risk of torsional interaction.

**Table 5-1**
**Determining the Need For Detailed Studies or Shaft Inspection**

| Type of Torsional Incident | Susceptible Machines | Circumstances | Need For Detailed Study or Shaft Inspection |
|---|---|---|---|
| Severe out-of-phase synchronization and major faults on low side of main step-up transformer. | All units | Operator error or equipment malfunction. | If out-of-phase exceeds 15 degrees. |
| SSR | All units within one to two buses away and connected directly to the same transmission voltage level as the series capacitor. The frequency scanning tool discussed in Appendix C can be used as an initial screening method for conditions conducive to SSR. | Network configuration changes due to fault and tripping of lines leading to SSR. | Based on frequency scanning tool if cases are identified with a resonant peak (or significant negative damping torque) at or within a few hertz of a torsional mode, more detailed studies will be necessary to identify a means of mitigating SSR (see Appendix C). |
| Severe transmission line three phase fault or severe line switching incident. | "All", and particularly those connected to lines using breaker high speed reclosing (HSR). | Act of nature or accident. | Multi-phase faults on lines emanating from the power plant or if HSR is practiced at or up to one bus away from the plant. If any of these incidences result in transient mechanical torques greater than that observed for a machine terminal 3-phase fault, they are of particular concern. |
| DDSO | Turbine-generator with a unit interaction factor (UIF) of 0.1 or greater (see Appendix D). | Proximity to steel mill converters, HVDC, SVC etc. | Detailed study may be needed if high UIF found (see Appendix D). Solution is typically in control tuning, filtering and supplemental damping controls. |
| Manual or Automatic (after long delay, many seconds to tens of seconds) reclosing of a transmission line emanating from a power plant | All units in the plant | Regular Operation of Transmission System | If load angle across the closing breaker is high enough to result in a transient (step) change in the machine electrical power of greater than 0.5 pu on the machine MVA rating. |
| Any | Any | Major retrofit or work on turbine-generator that results in a significant change in the mass/dynamics of shaft components (e.g. removing a rotating exciter, rotor replacement, blade replacement etc.) | Need to recheck and evaluate the effect of such activity on the torsional dynamics of the turbine-generator and how this might impact its sensitivity to network events. |

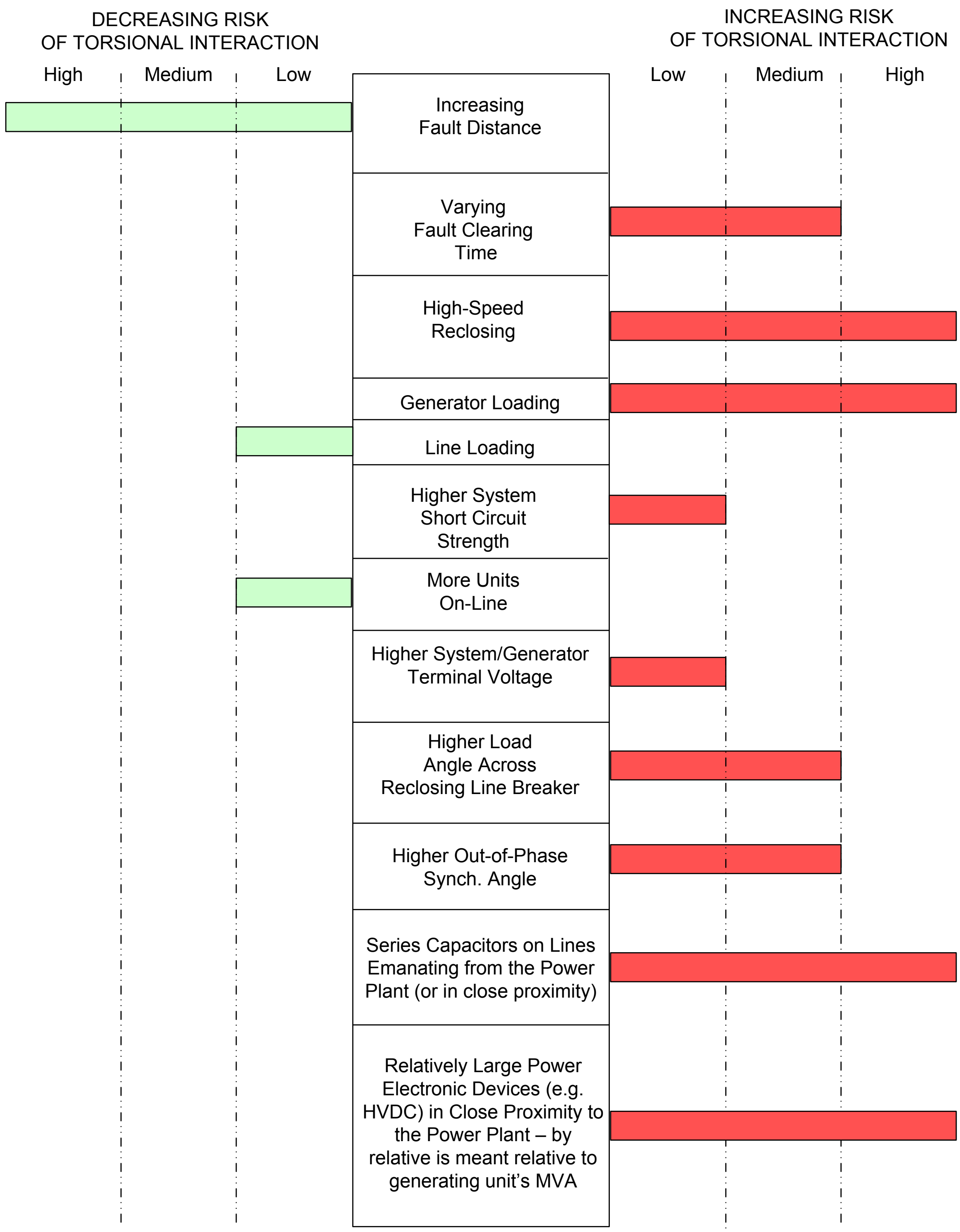



**Figure 5-1**
**Diagrammatic representation of how various factors affect the risk of torsional interaction on a turbine-generator—these are based on the results of this report.**

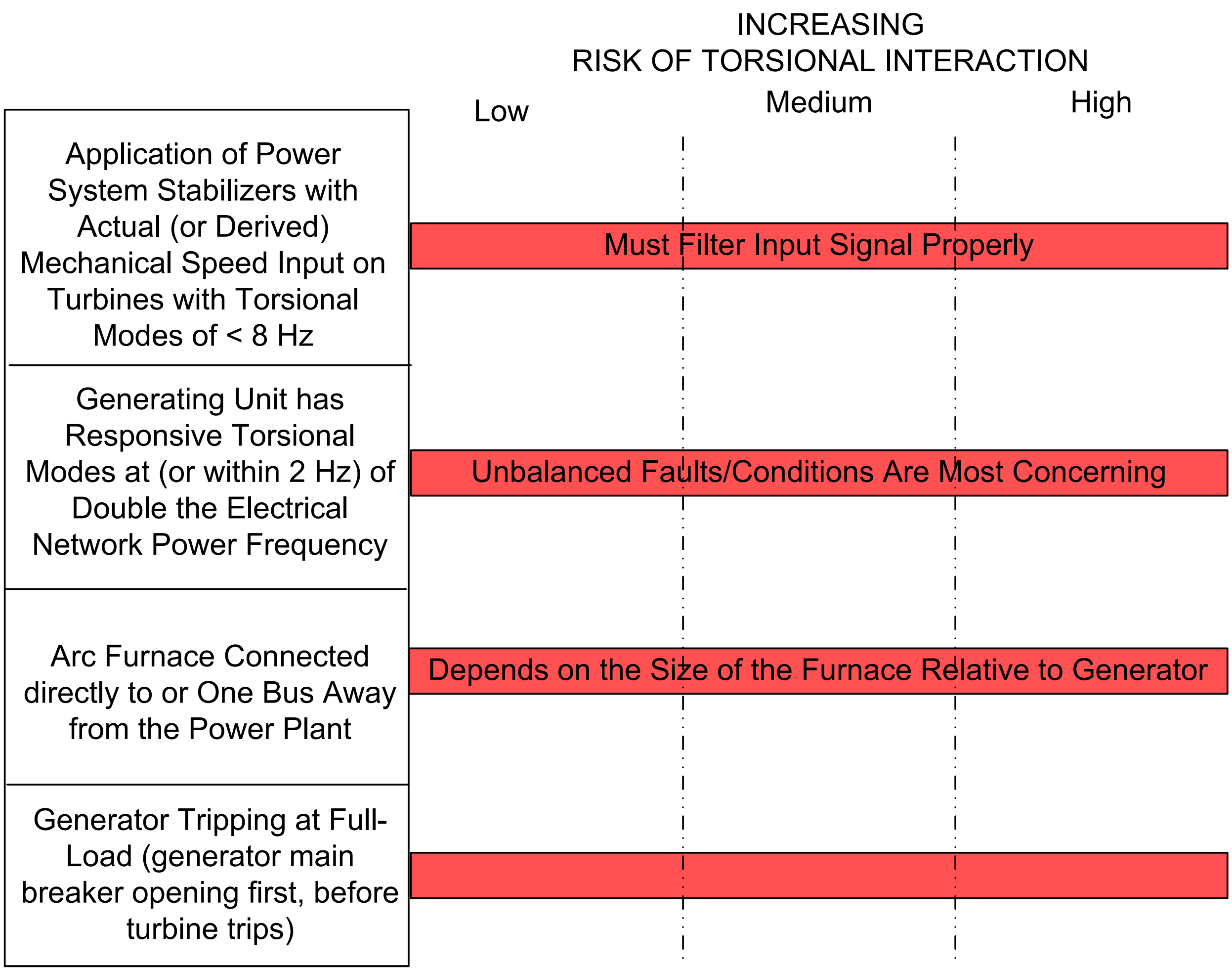



**Figure 5-2**
**Diagrammatic representation of other factors (not studied here) that are known to affect the risk of torsional interaction on a turbine-generator.**

In addition, the general and significant observation made was that severe transmission faults (such as 3-phase to ground faults) within close proximity to the plant but on the transmission system may actually give rise to transient torques that are more severe than faults directly on the terminals of the generator. This suggests that repeated and severe faults in the vicinity of a plant (e.g. within 50 or so miles) could result in crack formation on the turbine generator shaft. Such cracks could then be further propagated by large number of low magnitude torque cycles (e.g. due to typical electrical load imbalance and the resultant negative sequence currents), since once a crack has been initiated there is no definable endurance limit associated with the material.

The ZoV for multiphase faults was identified for the 1,500 MVA machine for multiphase faults in the transmission system. Faults beyond the boundaries of this zone would not produce a peak torque on any of the shafts of this machine larger than those seen for a terminal fault on the machine. This limit was chosen as a screening guide and it was found that it provided a much more conservative limit for the 1,800-RPM machine than for the 3,600-RPM machine that was modeled. For more precise limits the plant operator should contact the turbine generator suppliers for information on the fatigue capability of the shafts. A general procedure for defining the ZoV is provided in Section 4.

The limitted investigation of the effects of high speed reclosing showed much larger ZoV where unsuccesful reclosure at critical timing could produce shaft torque greater than terminal faults. This finding suggests HSR reclosing poses a high risk for torsional interaction for the steam-turbine and generator. The risk may even increase when transmission line or substation buses are taken out for maintenance. The plant is strongly advised to discuss the issues with the transmission operator.

An objective of this project was to catalogue transient grid disturbances that have been known to cause (historical) torsional interaction concerns. This was done through a search of technical literature, a questionnaire mailed to over 100 plant and system operators and telephone interviews with selected plants. A general conclusion from these reviews and interviews is that for most plants there are a relatively low number of events that are noted inside the plant. It was noted from several of the interviews that due to a change in ownership of the plant or turnover of plant personnel there was not a complete record of the transients that the plant had seen. Only two of the plants reported having monitoring equipment that could record the response of the shaft system to transmission system disturbances.

One prudent recommendation is that large power plant owners should consider investing in state of the art digital fault recorders, which are able to capture data associated with a network disturbance as seen from the power plant. Capturing, storing and post-processing of recorded network disturbances, as seen from the power plant, can significantly help to better document and quantify the potential impact of network disturbances on the turbine-generator shaft. At a minimum, all three phase voltages and currents should be recorded preferably at the machine terminals and at the power plant switch yard. The additional instrumentation required to record unfiltered electrical power out of the generator and velocity deviation at one or two points along the shaft is not difficult and it adds significant information about the impact of system events.

In the course of the study EPRI received models of two additional turbine generators that were not incorporated into the study. One of the models was quite similar to the one used for the 1,800-RPM machine but the other, also for a large 1,800-RPM machine, had lower torsional natural frequencies. The first mode was near 5 Hz rather than the value of 8.1 Hz for the machine modeled in the study. A similar study for the machine with lower natural frequency should yield similar results. However, the timing of fault clearing or reclosing operations that result in the maximum transient torques would clearly change due to the different modal frequency. If there were a concern with other interactions such as SSR or DDSO, the characteristics of these other machines would greatly influence the results. It would be more difficult to provide filters or other modifications to active controllers like those used in HVDC converters to both provide rapid control and avoid destabilizing the torsional frequency. Material in Appendices C and D provide more information about these subjects.

# 6 RECOMMENDATIONS FOR FUTURE WORK

For future work it would be fruitful to apply the approach presented in Section 4.7 to perform detailed analysis for an actual system where detailed information is available of the transmission system and the power plant, including S-N curves (curves showing the number of stress cycles as a function of stress amplitude before crack initiation) for the shaft material of the various shaft segments of the turbine-generators. This would allow a detailed investigation and an ability to compare the observed torsional stress on the turbine-generators to both the transient torques observed for machine terminal faults and to the S-N curve. In this way we could determine how conservative (or pessimistic) a metric the peak observed transient torques for machine terminal faults are. Also, a more detailed analysis of high-speed reclosing (HSR) in such a case would be fruitful to further investigate the potential impact of HSR even at relatively remote buses.

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# 8
# GLOSSARY

Some of the terms used here have been copied from [1]. It is recommended that the reader refer to that document if further clarification is needed.

**Air-Gap Torque** is the electromagnetic torque that acts on the generator rotor body. The generator rotor body is that part of the generator rotor that has axial coil winding slots. The torque is approximately uniformly distributed along the length of the generator body. This torque generally has a steady-state component as well as frequency components which most often are at the harmonics of the electrical system frequency. The unit is lbf.in or N.m in English and SI units, respectively. In the electrical engineering literature, air-gap torque is often also commonly referred to simply as **machine electrical torque** or torque of **electromagnetic origin**.

**Back-up clearing**. Although a rare occurrence, it is sometimes possible for a circuit breaker to open to clear a transmission line fault. This may be due to failure of the primary relay protection system or a mechanically failure in the breaker itself. Under such event, the backup protection relays will operate to isolate the fault which results in a longer fault clearing time and often in isolation of a larger number of elements (lines, transformers, bus sections etc.). – see also fault clearing time.

**Complement of a transmission line electrical natural frequency** is defined in this document as the electrical system frequency (60 Hz in USA) minus the transmission line electrical natural frequency. It has relevance for series capacitor compensated transmission lines. The unit is cps or Hz in English and SI units respectively.

**Device Dependent Subsynchronous Oscillations (DDSO)**—see Section 2.3.

**Damping Torque.** This is the component of torque (can be of either mechanical or electrical origin) that is in phase with variations in shaft speed (i.e. varies in time in step with speed variations). By convention positive damping torque acts to increase the damping of shaft oscillations at a given modal frequency, while negative damping torque acts to increase the magnitude of shaft oscillations. Typically, all source of mechanical damping torque (e.g. friction) result in positive damping. On the other hand electromagnetically induced air-gap damping torque may be negative (see Appendix C and D for discussion on SSR and DDSO). If the sum of these two components (mechanical and electrical damping torque) is negative for a given torsional mode, then the mode becomes unstable and can result in growing oscillation that will eventually damage the turbine-generator shaft.

**EMTP type simulation.** EMTP stands for Electromagnetic Transients Program where the fast dynamics of transmission lines and power devices are represented explicitly and whose voltages and currents are solved instantaneously. The first such program with this name was developed at

Bonneville Power Administration (BPA) by Hermann W. Dommel, and W. Scott Meyer. There are several EMTP type programs today including ATP for Alternative Transient Program which is freely available from BPA. Other proprietary programs include SimPowerSystems based on Matlab/Simulink®, DIgSILENT®, Microtran®, EMTDC/PSCAD® and EMTP-RV®.

**Endurance Limit or High Cycle Fatigue limit** is a property of some materials. If the alternating stress falls below this limit, in theory an infinite number of fatigue cycles can be sustained without a fatigue crack being initiated. High Cycle Fatigue is associated with cyclic strain levels for which deformations are elastic (reversible). Conversely, Low Cycle Fatigue occurs when cyclic loads produce strain levels that are plastic (not reversible).

**Equivalent source and source impedance**. In EMTP simulations it is typical and accepted practice to represent large portions of a power system at the boundaries of a model (typically one of more buses away from the machine or line under study) with an equivalent constant voltage source behind an equivalent impedance, referred to as the source impedance.

**Fatigue** is the tendency of materials to crack and then finally fracture under repetitions of stress or strain at a level considerably less than the static fracture strength of the material. Fretting Fatigue can occur when relative motion of microscopic amplitude occurs between two metal surfaces. The endurance limits of the materials involved are substantially reduced by the fretting action.

**Fatigue Life.** One hundred percent (100%) loss of component life corresponds, in the context of this document, to when a fatigue crack is initiated. The component of course has some life left before a crack propagates to a size where fracture (component separation) occurs. This additional life is often discounted in life estimating because of the catastrophic consequences that can arise if a component fractures and because cracks can grow quickly due to fatigue or other mechanisms.

**Fault Clearing Time**. When a fault occurs on an overhead-transmission line it is detected by a protection relay. Typically, for extra-high voltage transmission lines, impedance based distance-relays are used as the primary means of protection. The relay measures bus voltage and line current, and from these measurements calculates the apparent impedance of the line. If this calculated impedance falls inside a given range (i.e. decreases dramatically) this is an indication of a fault on the line; the distance of the fault may also be extrapolated from the calculated impedance as compared to the known impedance of the line. The total time taken by relays to perform this detection process, any intentionally set delays before issuing a command to the line circuit breakers to open and then for the circuit breakers to actually fully open is referred to as the fault clearing time.

**High-Speed Reclosing**. This is a common practice used on extra-high voltage transmission lines (i.e. typically for transmission lines at 115 kV and above). Most faults on overhead transmission lines are intermittent, that is they last for a short period of time (e.g. lightning strikes, tree contacts that burn out quickly, etc.). Thus, for the sake of system stability and reliability, when a fault occurs and is cleared by opening of line-end circuit breakers, often an automatic high-speed reclosing attempt is made by controls where the circuit breakers on one end of the line are closed again within a fraction of a second after the line has been completely opened. The expectation is that the fault has disappeared by this time and the line can be reclosed. In most cases this is true and subsequently the other end of the line is also automatically reclosed within a few cycles of system frequency. However, in some cases where the fault may be a permanent fault the reclosing attempt will indicate to protective relays that the fault has not been removed and thus the line will once again clear—this is commonly called an **unsuccessful reclosing attempt**.

**Infinite Bus**. An infinite bus is a mathematical ideal of a very large power system. It is a constant voltage source with infinite inertia so that neither its voltage nor the frequency of the voltage can vary.

**Load Angle**. When manually (by operator action) reclosing a transmission line (re-insert into the system), there will be a phase angle difference between the system voltage on the opposite sides of the circuit breaker that is used to completely re-insert the line into the transmission system. This phase angle difference (referred to here as the "load angle") is determined by power flow in adjacent paths on the transmission network and is an indication of the initial transient inrush of power into the line once it is re-inserted into the network.

**Negative sequence** currents arise when there are imbalances in the phase currents in a three phase network. The three phase voltage and current system is balanced when the three phases are 120 electrical degrees apart in time relative to fundamental frequency and have the same magnitude. When there is a line-to-ground fault for example, the voltage at the faulted line becomes depressed and the system becomes unbalanced. The currents in the faulted and intact lines need to be calculated to determine the setting of protection relays for example. This calculation involves a mathematical transformation into three symmetrical 60-Hz components which are the so called "zero", "positive" and "negative" sequence currents. The interaction with the generator rotor differs for positive and negative sequence. When negative sequence current is imposed at the stator winding, the rotor that physically rotates at 60 Hz will "see" a magnetic field that rotates at 60 Hz in the opposite, negative sequence, direction. The rotor field that under positive sequence is not exposed to any magnetic field other than the dc field is now exposed to a 120-Hz magnetic field. Negative sequence induced currents now generally flow on and close to the surface of the rotor, and if large enough can cause local overheating and arcing at discontinuous joints such as the retaining ring and slot wedges. Negative sequence currents will introduce a 120-Hz air-gap torque component that is additive to the steady-state torque.

**Per Unit (pu) system**. The per-unit system is use in electrical engineering calculations to simplify calculations. Under the per unit (pu) system all physical quantities are expressed as a per unit ratio of a defined base quantity. To fully define a pu system four base quantities are needed a base voltage, base current, base power and base impedance. For example, consider an electrical generator rated at 13.8 kV RMS and 100 MVA. For this machine we could chose the base voltage to be 13.8 kV, the base power to be 100 MVA. Then instead of saying that the machine is operating at 13.8 kV RMS and 90 MW, we could say that it is operating at 13.8/13.8 = 1 pu voltage and 90/100 = 0.9 pu load.

**Polar Moment of Inertia** in torsional vibration is analogous to "mass" in transverse or lateral (rotor bending or flexure) vibration. For a given body of rotation it equals the summation of the products of all elements of mass of the body times the square of the perpendicular distance of each element of mass from the rotational axis. The unit of polar moment of inertia is lb.in2 or kg.m2, in English and SI units respectively.

**Poles—Two pole (2P) and Four Pole (4P) Generators**. The generator fields (rotors) of large steam turbine-generators have either two poles or four poles depending on whether they rotate at 3,600 or 1,800 RPM. In each case, power at 60 Hz is produced by the generator. 2P units are generally used in fossil fuel applications and 4P units for nuclear installations.

**Single-Pole Switching**. Most faults on transmission lines are single-line to ground faults. Thus, for the sake of increasing system reliability and stability, single-pole switching is implemented on many extra-high voltage transmission lines. When a single-line to ground fault is detected by protection relays, the faulted phase of the line is opened by circuit breakers to clear the fault. Then on the assumption that the fault has completely cleared (since most faults are intermittent) the phase conductor is reclosed automatically within a fraction of a second. In the rare case that the fault still persists, the entire line is then opened.

**Short Circuit Level**. The short circuit level of a system is defined as the level of fault current available at a given bus. For example, if under a given system condition the 3-phase fault current available at a 230 kV network bus was 10,000 A rms, then the short circuit level is defined as $230{,}000 \times 10000 \times \sqrt{3} = 3{,}983$ MVA. As short circuit level increases the system is said to be stronger. If system topology (that is number and status of transmission lines and transformers in-service) does not change, higher short circuit strength at a bus corresponds to a larger amount of generation being on-line through out the system. Thus, this typically translates to faster voltage recovery following disturbances and greater system inertia (i.e. smaller changes in system frequency for a given amount of load/generation loss).

**Stress and Strain** are fundamental parameters in structural analysis. Stress is the intensity of a load applied to a structural member at a specified location and is the localized load per unit area. The unit of stress is lbf/in2 or N/m2, in English and SI units respectively. In the English system the unit is often labeled “PSI” (pounds per square inch) or commonly “KSI” where 1 KSI equals 1,000 PSI. Strain is a deformation parameter that results from the load application and equals the extension of the member divided by its original length and is non-dimensional. Strains may be referred to as elastic strains if after removal of the load the member returns to its original geometry. Plastic strain arises if the load is large enough for yielding (see Yield Point definition -14.32) to occur in the member.

**Stuck-breaker**. When a circuit breaker fails to open in order to clear a fault, it is said to be a stuck-breaker.

**Subsynchronous** and **Supersynchronous Frequencies** refer to those below and above the transmission system power frequency respectively. The electrical transmission system frequency in the USA is 60 Hz. In some other countries it is 50 Hz.

**Subsynchronous Resonance (SSR)** see Section 2.2.

**Synchronizing Out-of-Phase (SOP)** can result when connecting the generator to the power system during the start-up synchronizing process. Ideally during synchronization, the phase of the voltage on either side of the circuit breaker will be equal, but practically this is never achieved either with a manual process or with an automatic synchronizer. An SOP angle of 10 degrees or less generally results in vibration responses that can be sustained by a machine an indefinite number of times without damage, and synchronizing in this widow is practical even with a manual process. Mistakes have occurred, though, that have resulted in synchronization at close to the worst possible angle resulting in significant machine damage.

**Telemetry and Transfer Tripping**. Faults on extra-high voltage transmission lines are typically detected by impedance based distance relays (see fault clearing time). When a fault is detected by a protection relay it will estimate the distance of the fault from the end of the transmission line where the relay is located. The delay between fault detection by a relay and the subsequent command sent to the line circuit breaker to open is set based on distance Zones. For critical extra-high voltage transmission lines (particularly those emanating from large power plants) to avoid any excessive delays in fault clearing, telemetry is used to transfer trip the remote end of a faulted transmission line. Once the relays on the end of the line closest to the fault detect the fault an initiate opening of the near end circuit breakers, a signal is automatically sent by the relay (through communication channels such as optical fiber) to the circuit breakers on the remote end of the line to also open.

**Torsional Natural Frequency and Mode Shape**. A frequency for which the inertia and stiffness forces in a torsional system are completely in balance. In the absence of damping, forcing a mechanical system at any one of its natural frequencies will theoretically result in an infinite vibration response. When the system is responding at one natural frequency in the steady-state its deflection pattern (displacement as a function of axial position) will have a unique shape called the mode shape. Mode shapes are commonly normalized to a maximum value of one. There is a unique mode shape associated with each natural frequency.

# A
# SHAFT MODELS FOR THE UNITS

## Generic 1800-RPM Unit (data based on actual anonymous nuclear unit)

**<u>Generator</u>:** MVA = 1,500 (all values in pu on this MVA base), 0.9 pf

Ra = 0.002
Xl = 0.22
Xd = 1.99
Xd' = 0.37
T'do = 10.0
Xd'' = 0.28
T''do = 0.033
Xq = 1.86
Xq' = 0.564
T'qo = 0.48
Xq'' = 0.28
T''qo = 0.055

**<u>Exciter</u>:** EXST1

Ka = 250
Ta = 0.01
Tf = 1.0
Kf =0.05
Tr = 0.02
Tc = 1.0
Tb = 1.0
Kc = 0.05
Vimax = 0.2
Vimin = -0.2
Efdmax = 10
Efdmin = -6

**<u>Shaft</u>:** All values in pu on 1,500 MVA; assumed 1,800-RPM machine with 2 pole pairs. No exciter mass since exciter is static.

| Power Fraction (pu) | Inertia (kgm2/rad) | Self Damping | Mutual Damping | Spring Constant (Nms/rad) |
|---|---|---|---|---|
| (HP) 0.125 | 7335.88 0 | 0 | 0 | 2484192000 |
| (HP) 0.125 | 7057.94 0 | 0 | 0 | 235266000 |
| (LP1) 0.125 | 38515.45 | 0 | 0 | 1883484000 |
| (LP1) 0.125 | 38544.93 | 0 | 0 | 363679200 |
| (LP2) 0.125 | 38544.93 | 0 | 0 | 1883484000 |
| (LP2) 0.125 | 38574.41 | 0 | 0 | 448293600 |
| (LP3) 0.125 | 38574.41 | 0 | 0 | 1883484000 |
| (LP3) 0.125 | 38603.89 | 0 | 0 | 603826800 |
| (GEN) 0 | 70832.05 | 0 | 0 | |

***Note:*** The data provided for the 1800 rpm machine by the anonymous source indicated an equal distribution of power for all of the turbine sections (as shown in the table above). This was used both for the sake of simplicity and in order not to skew the data unnecessarily. In practice, most units of this size will likely have a somewhat less symmetrical distribution of power on the turbine-generator shaft with slightly more power developed in a single HP stage than any single LP stage. Detailed analysis for a given turbine-generator would need to properly reflect the power fraction of each turbine stage.

## Generic 3600-RPM Unit— IEEE SSR Benchmark Case 1 [4]

**<u>Generator</u>:** 892.4 MVA, 0.85 pf

Ra = 0.002
Xl = 0.13
Xd = 1.79
Xd' = 0.169
T'do = 4.3
Xd'' = 0.135
T''do = 0.032
Xq = 1.71
Xq' = 0.228
T'qo = 0.85
Xq'' = 0.200
T''qo = 0.05

**<u>Exciter</u>:** The exciter was modeled electrically using a simple static exciter (essentially ignoring the rotating exciter time constant). In most studies considering transient torques the electrical circuit of the exciter is often not modeled as it has little influence on the resultant shaft transient torques. The exciter mass and shaft connecting the exciter to the generator are represented in the spring-mass model.

**<u>Shaft</u>:** All values in pu on 892.4 MVA; assumed 3,600-RPM machine with 1 pole pair

| Power Fraction (pu) | Inertia (kgm2/rad) | Self Damping | Mutual Damping | Spring Constant (Nms/rad) |
|---|---|---|---|---|
| (HP) 0.3 | 1166.62 0 | 0 | 0 | 45693376.74 |
| (IP) 0.3 | 1953.92 0 | 0 | 0 | 82682689.53 |
| (LP) 0.2 | 10783.35 | 0 | 0 | 123182507.3 |
| (LP) 0.2 | 11104.15 | 0 | 0 | 167732543.6 |
| (GEN) 0 | 10906.73 | 0 | 0 | 6675403.95 |
| (EXC) 0 | 429.698 0 | 0 | 0 | |

**<u>Note</u>:** The turbine-governor was not modeled for either unit as it has little to no impact on the observed transient torques in the time frames under study here.

# B
# PLANT INTERVIEW NOTES

One of the objectives of this project was to catalogue recent transient grid disturbances that may have caused torsional interaction concerns. As stated in Section 3, part of this effort included the distribution of survey document and subsequent interviews with generating plat owners. Additionally, written input was requested from some plant owners for which known torsional interactions events have occurred. The following interview summaries were compiled from meeting notes taken by the project team during the teleconference interviews or from the written submissions of specific plant owners.

## Exelon

Exelon staff noted that there was an occurrence over the past 18 months at a plant on their system where a bearing vibration change was noted and possibly linked to something on the grid. The event was a single phase-to-ground fault on a 345-kV transmission line that was cleared in 4.5 cycles. The fault was believed to be caused by bird excrement on a tower and insulator string about 35 miles from the plant. There was a possible reclosing failure, but records were not complete.

They also noted that there had been at least one lightning strike near another plant and other disturbances in the transmission network, but they did not know of any observed changes in operation of the turbine generators that would indicate that the plant was affected.

## Power Plant in Texas

Their experience with torsional issues is limited to the turbine blade failure that occurred in late 2002. This occurred after a spare generator rotor was installed on Unit 2. The rotor had small differences in manufacture from the original rotor. These differences tuned one of the torsional modes involving the generator and low pressure turbine rotors closer to 120 Hz. After a few days of operation, there was a blade failure and subsequent inspection showed a number of other cracked blades. Modifications were made to the turning gear couplings as well as to the profile of the turbine disc to detune the mode.

The plant has installed a torsional monitoring system on their nuclear turbine generators. These monitors were installed in January, 2003 after they had a turbine blade failure on a Unit 2 low pressure turbine—this failure occurred in December, 2002. These monitors use 2 probes over a toothed wheel at the exciter end of the machine and two probes over the turning gear. These probes are mounted 45 degrees apart and their output is summed to eliminate noise due to lateral vibration. They also have a key phasor signal from a toothed wheel.

The monitors can see the effects of transmission system transients such as the trip of other large generating units in the region. The plant representative said that the frequency changes in the Texas grid have increased since deregulation of the markets in Texas. The reason for this change is not clear.

Their plant is connected to the grid by 5 transmission lines. These lines are usually heavily loaded with their plant normally operating at full power The plant representative did not know of any system events with shocks large enough to have been heard or felt inside the turbine hall. The plants have a formal shutdown procedure if a hurricane approaches the coast. However, there were no recent hurricanes in their area to require shutdown.

## Arizona Public Service (APS)

APS has installed digital fault recorders and torsional monitoring equipment at their nuclear plant and two fossil plants. These monitors use pickups mounted over toothed wheels and turning gears along the shaft together with unfiltered electric power signals at input. They have a torsional (spring-mass) model of the rotor system and have implemented a cycle counting procedure to get an estimate of fatigue damage.

These models show that there are very few events in the transmission network that even register torque cycles above the fatigue limit on any of the machines. They had a three-phase fault on a 500-kV line connected to the nuclear plant 500-kV bus. This fault was cleared in about 3 to 4 cycles. Their analysis estimated roughly 0.1% fatigue life for this event. They have information about two 3-phase faults in the vicinity of the nuclear plants during the past 20 to 30 years, both incidents were due to human error (i.e. leaving a workman's ground on a bus and re-energizing the bus).

## Pennsylvania Power & Light (PPL)

A torsional event was experienced in 1993 and a detailed investigation was conducted with their transmission people to determine the cause. When they recently tried to update the information concerning faults in the transmission system, they found that with deregulation they cannot share the information learned previously[B-1]. The plant representative believes that this prohibition includes the reports describing the events prior to 1993.

On the day of the disturbance two blades came off the LP1 turbine of their Unit 1. At that time the turbines had 38 inch last row blades. The turbine generator manufacturer believed that their calculations were accurate to within 2 Hz and prior to this event had not issued any bulletins related to this turbine. They had issued bulletins related to their turbines with 43 inch last row blades following the failure of the A unit in Asia. That unit had seen a considerable amount of operating time at frequencies below 60 Hz because the system was small and often overloaded. The plant representative stated that in the United States a long time for off frequency operation would be about one minute.

[B-1] FERC Interpretive Order, issued 2/16/2006, permits Transmission Providers to communicate with affiliated and non-affiliated nuclear power plants to enable the nuclear power plants to comply with NRC requirements.

The turbine generator manufacturer recommended installation of a torsional monitor that would measure power oscillations in a 2-Hz frequency band around 120 Hz. If oscillations were above a threshold and within the band for a minute the monitor would alarm. Based on the fact that the units had not experienced any events that existed for a minute, PPL chose not to install this monitor. PPL's study showed there had been no faults between the units and switchyards. There had been 14 faults on the 230-kV network near the plant, and 3 faults on the 500-kV network during the year that their machine's turbine blades failed. The longest clearing time was 42 cycles.

The failed blades showed multiple beach marks. Their metallurgical engineers said progression was over at least one year and probably over the life of the rotor. About a thousand cracks were found on other blades when they checked the unit. The failed blades had been around the number 7 bearing. Vibration changes resulted in tripping the unit. The inspections showed that blades around the number 8 bearing were also very close to failing, had the unit not tripped when it did. In 1988 they replaced rotors with monoblock rotors. Unit 2 had 4 calendar years of service with the new rotor, but had blades from unit 1.

Over 11 years from June 1982 to July 1993, they researched the history of transmission events. There were 90 incidents (faults). All except for four of these ninety events were cleared in 7 or less cycles, four events lasted as long as 42 cycles. They tried to categorize the events based on where the fault was on the line and how the reclosing occurred. The data was not sufficient to get everything they needed so they categorized into low, medium and high negative sequence. These events were then classified for the two units as follows:

- Unit 1: 230-kV unit
  - 36 events with low negative sequence
  - 26 events with medium negative sequence
  - 2 events with high negative sequence
- Unit 2: 500-kV unit
  - 26 events with low negative sequence
  - 9 events with medium negative sequence

They tried to update data from 1993 on but could not get any information.

The two units do not connect at the same voltage level. Unit 1 connects at 230-kV, Unit 2 connects at 500 kV. Since there were more events on the 230-kV lines that resulted in high negative sequence content, and the failure of Unit 2 was due to a 120 Hz resonance, PPL concluded that these 230-kV disturbances had the greatest impact on the failed unit even though there was a network transformer between the voltage levels. Seven days prior to the blade loss there was a slow clearing fault (42 cycles) on the 230-kV network near the plant. The system lost another unit over 600 MW, 85 minutes before failure, which caused a 0.02-Hz frequency decline. They see the frequency shifts for loss of large units anywhere in the Eastern interconnection. They have had several full load trips over the life of the units. They make changes every time they have an incident to correct problems. Consequently Unit 1 has more shocks than Unit 2. The torsional tests performed by the turbine generator manufacturer during commissioning required a 10 degree out of phase synchronization which the PPL representative believes was the largest shock the units have experienced. There have not been very many long duration incidents and not any close in faults that he recalls, and he believes the cumulative number of cycles is less than one minute for either unit.

## Tennessee Valley Authority (TVA)

There have been 2 significant events near a TVA's plant. The first was in November 2005 and the second in March 2006. The first event was due to a massive lighting strike that causes a 3-phase fault roughly 40 miles from the plant on a 500-kV line emanating out of the plant. Later analysis indicated that this was the largest strike measured in the US. The 2nd event was due to a workman's ground being left on a 500-kV bus (15 miles from the plant) and re-energizing the bus into a 3-phase fault. Both events were cleared in 2–3 cycles. For each event one of the two units tripped. The trip was attributed to the new digital controls on the unit. It is believed that the more sensitive digital controls incorrectly picked up on overspeed when the actual phenomenon was large speed oscillation due to the torsional response to the 3-phase fault.

A retired expert was hired after the events to perform modeling work for TVA. Fairly accurate simulation of the events were performed, but there were no event recordings to compare the simulations with. Fault recordings were not good. After the first event both units had vibration issues due to some imbalance, presumably induced due to significant oscillations and vibrations due to the 3-phase fault.

The plant is connected to the network through 7 fairly long 500-kV transmission lines. Line reclosing on the 500-kV lines is done after 17 seconds, reclosure is done first on the remote end and if successful then re-synch at generator end. Automatic reclosing on 161-kV lines are done at 45 cycles (without carrier) and 15 cycles (with carrier) simultaneously at both ends. There have been tens of events in the life of the plant but no appreciable shaft fatigue to the knowledge of the plant owners. There are no torsional monitors at the plant.

Another TVA plant has one unit connected through 2 500-kV lines and the other connected through 3 relatively short 161-kV lines. It is believed that even though there are more lightning flashovers on 161-kV lines than 500-kV lines, the shorter length of the 161-kV lines makes the lightning exposure for the unit connected at 161 kV less than for the unit connected at 500 kV. The plant had one event that isolated one unit on a single 500-KV line. The excitation had high gain and no PSS so the unit started to oscillate. The oscillation was in the 100–200 MW range and clearly due to electromechanical oscillations at a frequency of about 1 Hz and not considered to be a torsional event.

## Pacific Gas & Electric (PG&E)

Their plant has two units connected to the 500-kV system through three transmission lines to two substations on the West coast intertie. The plant is connected to one substation with two 500-kV lines and the other substation with a single 500-kV line. The lines are about 80 miles long and the two substations are about 150 miles apart. This arrangement results in a relatively stiff connection of the plant to the main North/South 500-kV lines. At the substation connected by 2

500-kV lines, there are several 500/230 interchange banks that connect to local generation and loads.

The turbine generators have experienced torsional impulses since 1992 that have each coincided with an off site disturbance (some originating more than 600 miles away). The effects on the turbine generator shafts vary. A few have resulted in loud bang type noises on the turbine deck; others result in noises described as rumbling and tones coming from the turbines. Most recently there have been immediate pitch changes in the normal turbine noise with a corresponding and immediate drop in measured frequency. These events do not occur on on-going bases. There may be a two or three year period where there are no such events. The first event was the result of a trip of a 500/230 transformer at the substation 80 miles away. Other events have been associated with the 230-kV system at or near that substation also. All other events have been traced to an initiating fault and consequent switching directly on the 500-kV system but north of the California/ Oregon border.

An interesting aspect of a typical event (especially if it is initiated directly on the 500-kV system at a point very distant from the plant) is that there is seldom much of an indication of the event in plant instrumentation and it seldom is picked up with the high speed fault recorders at the switchyard or at the substations at the far end of the lines from the plant.

In summary, it seems that the system transient causing a response at the plant does not have as much to do with the initiating fault as does the associated switching used to clear the fault and stabilize the system. There may be a connection between the impedance between the plant and the event since a nearby 230-kV event can act a bit like a distant 500-kV event. Grid actions such as capacitor bank automatic shunting and reinsertion, as well as some high speed breaker reclosing may be involved in these events.

## Southern California Edison (SCE)

The plant personnel sent a presentation entitled "Case-Study of Shorted Turns Development". It was presented at an EPRI conference on shorted-turns in turbo-generators in July 2004. The presentation discusses two incidents in April and October 2003 where rotor shaft vibration of the unit 3 generator exhibited step increases. The increase was coincident with severe grid disturbances. Switchyard recorders that were triggered by negative sequence currents recorded these disturbances. The events were initiated by system faults, but the fault type, transmission line switching operations and extent of the disturbance was not provided. The presentation stated that a large unit located about 350 miles from the plant motored for a few minutes during the October event.

Plant analyses indicated that the vibration increase was the result of shorted or partially shorted turns in the generator rotor winding. The plots showed sharp increases in generator field voltage during the events that coincided with the vibration increase. Figure B-1 from the presentation shows the power swings that were recorded by the plant computer. This plot is the derivative of power, which amplifies the response. It clearly shows the damped oscillation at the system frequency of about 1 Hz as well as several seconds of activity at a higher frequency, which was most likely, a torsional frequency of the turbine generator rotor.

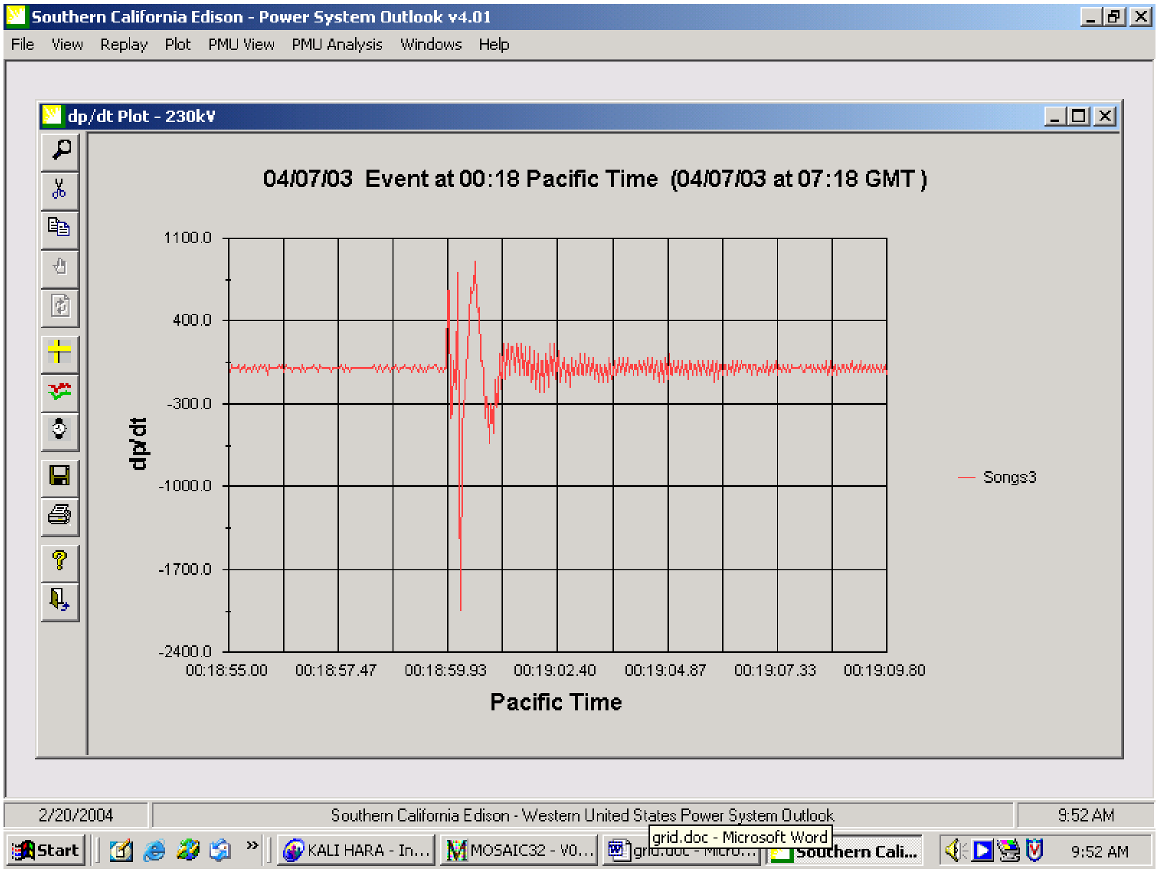


**Figure B-1**
**Plot of derivative of generator power with respect to time during a system event on April 7, 2003.**

Another slide in the presentation indicated that system events that impact the turbine generator are frequent. This illustration, reproduced as Figure B-2, shows the peak values of the derivative of generator frequency and derivative of system power for 65 events that occurred during the period from May 2002 to the time of the presentation in 2004. Although the April and October 2003 events were significant, many of the other events produced larger shocks on the generator and larger frequency excursions.

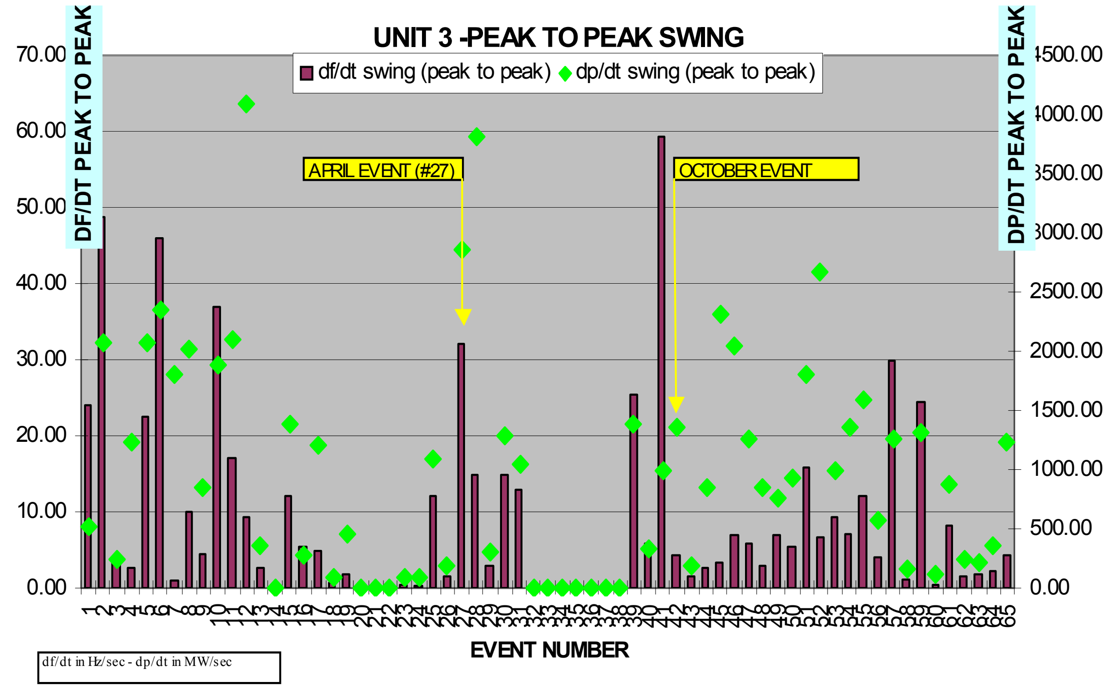


**Figure B-2**
**Peak swing in the derivative of frequency and power for 65 events in the Western grid during the period from May 2002 until mid 2004**

# C
# FREQUENCY SCANNING TECHNIQUE FOR IDENTIFYING THE POTENTIAL FOR SSR

The frequency scanning technique is based on the concept of estimating the total component of damping torque on the generator shaft that is of electromagnetic origin. That is, the component of electrical torque that is in phase with speed and thus results in damping speed oscillations [29]. By estimating this component of torque one can then identify if regions of resonance, which show-up as distinct and sharp negative dips in electrical damping torque, are in the vicinity of torsional modes of oscillation. The equation for estimating electrical damping torque based on the frequency scanning technique is given in [C-1]:

$$\Delta\sigma = \frac{Q_m^2}{4M_m}\left(\left(1-\frac{f_0}{f_m}\right)\mathrm{Re}\left(\frac{1}{Z_{LO}}\right)+\left(1+\frac{f_o}{f_m}\right)\mathrm{Re}\left(\frac{1}{Z_{LU}}\right)\right) \qquad \textbf{Eq. C-1}$$

Where:

$Z_{LO}$ is the generator and network impedance evaluated at the lower side-band frequency associated with a torsional frequency $f_m$.

$Z_{LU}$ is the generator and network impedance evaluated at the upper side-band frequency associated with a torsional frequency $f_m$.

$M_m$ is the modal inertia for mode “m”

$Q_m$ is the generator modal component of the mode shape for mode “m”

and

$$\gamma_m = \frac{Q_m^2}{4M_m}\left(1-\frac{f_0}{f_m}\right) \qquad \textbf{Eq. C-2}$$

where $\gamma_m$ is the interaction factor for mechanical torsional mode “m”.

The modal inertia, $M_m$, generator modal component, $Q_m$, and mode shape are all determined primarily by the mechanical characteristics of the shaft.

The following methodology can then be incorporated to screen for SSR:

- An electrical network model is developed on the transmission system in the vicinity of the turbine-generators under study. The model must explicitly represent the series capacitors in the transmission system. At the boundaries of the model, the neighboring electrical systems may be represented by an equivalent and source and transfer impedances. The decision of where the boundaries of the model are to be drawn is based on initial simulations in order to establish a simplified model (with equivalents at the boundaries) that yields network frequency scans at the units under study that are in agreement with the full system model. Typically, within heavily meshed power systems, capturing the transmission network within five to ten buses removed from the plants under study tends to be adequate.
- Identify all the turbine-generator units to be studied and based on mechanical models (see Section 2) identify their subsynchronous torsional modal frequencies and mode shapes.
- The technique by its nature allows the calculation of electrical damping for one generating unit at a time (i.e. one cannot simultaneous calculated electrical damping torques for all units in one simulation). Identical units must be treated with care [30].
- A frequency dependant network model needs to be used. Transmission lines, transformers, shunt elements etc. need to be represented as resistance, inductance and capacitances rather than constant impedance. Detailed line models such as used for high frequency electromagnetic transient analysis (e.g. J-Marti frequency-dependent models) are typically not needed. However, if particularly long lines are studied, it may be necessary to use a distributed parameter line model for greater accuracy.
- The turbine-generators under study are considered one at a time and a ranked list of network outages (transmission contingencies) is created that gradually lead to (or as close are realizable) a radial configuration between the turbine-generator and the transmission series capacitor(s). This may require going to extreme conditions (i.e. N-5 or more outages). Non-the-less the analysis should be performed. This helps to identify under what network conditions the system is susceptible to resonance.
- All the identified contingencies scenarios, one at a time, are screened for each study unit in order to identify the potential for SSR.

In performing SSR screening analysis they key factors to consider are as follows:

- Contingency scenarios that lead to a radial or near radial configuration between the turbine-generators under study and series capacitors on the transmission system, this typically leads to the worst resonant conditions.
- Consider various levels of series compensation. The higher the level of series compensation, the lower will be the resonant frequency on the rotor reference frame—that is higher levels of series compensation (a higher impedance capacitor that effectively compensations for a great portion of the transmission line) will result in resonances with lower frequency torsional modes. The lower frequency modes are often the least damped and most susceptible to destabilization.

- The amount and type of load will affect the resultant level of damping (i.e. the magnitude of the resonant peak—the load level does not have a significant impact of the resonant frequency).

Figure C-1 shows damping torque[C-1] plots calculated for an assumed configuration of a 1,500-MVA unit (see Appendix A) feeding a single radial 500-kV line connected to a stiff bus, which is series compensated. The resonant peak can be clearly seen and as expected the resonant peak grows in magnitude and decreases in frequency as the level of series compensation is increased from 10% to 90% of the line. In a comprehensive study, by generating families of curves similar to these one can evaluate when resonance occurs, if it occurs at or around the torsional modes of concern, and by comparing the amount of negative damping caused by resonance to the known (or estimated) level of mechanical damping available one can predict the likelihood of destabilization. It is extremely important to realize that mechanically damping can only truly be determined by measurement. Therefore, it may be prudent to perform field tests to quantify the level of mechanical damping (ref. [5] gives an example of field measurement of torsional damping using modern testing equipment) to better assess the likelihood of torsional instability.

Another potential problem with series compensation is that of induction generator self-excitation. This has been studied for synchronous generators, but based on generator design not encountered in the field [31]. This is a far more concerning problem for wind turbine generation, which incorporates induction generators [8].

Some of the common solutions to the SSR problem are:

- **Operational Strategies**—if SSR is identified to occur only under extreme contingency scenarios (e.g. N-5 or more outages) it may be quite feasible to put into place automatic operational strategies to by-pass all or part of the series compensation when multiple lines are outaged. This is an approach taken for many series compensated lines in the Western US system.
- **Reducing compensation level**—based on screen analysis, such as described above, one may be able to establish a compromise. Namely, a reduced level of series compensation that meets the needs of increasing system transfer capability, while keeping the resonance point high enough to avoid interaction with the critical torsional modes on the nearby turbine-generators. Often this strategy may be combined with the previous by segmenting the series capacitor into two or three parts and thus reducing the level of series compensation under certain critical contingency scenarios. Such an approach requires careful study.
- **Filters**—in the past many mitigation methods adopted the approach of supplying passive filters at the generating station [26], [2], [31]. This approach has not been implemented in recent years. The disadvantage with this approach is that every potentially affected turbine-generator requires a dedicated filter. Furthermore, each filter is necessarily one of a kind and requires extensive study to ensure that it will be effective under all potential system scenarios.
- **Excitation system supplemental control**—in this approach a supplemental damping controller is incorporated into the turbine-generator excitation system. The concept is similar

[C-1] Here the damping torque coefficient is shown, excluding the modal interaction factor.

to that of a power system stabilizer, however, the controlled is tune to provide damping at specific torsional modal frequencies [31]. Such applications require fast acting static excitation systems.

- **SVC/STATCOM**—this approach employs an SVC or STATCOM as a means of inducing damping torque on the turbine-generator shaft at torsional modal frequencies to eliminating the negative damping due to resonance [32].
- **Thyristor-Controlled Series Capacitor**—this is the most effective solution in the sense that replacing all or part of the series capacitor with a thyristor-controlled series capacitor (TCSC) [45] the source of the problem is essentially removed. Thus, with the TCSC the potential for SSR can be eliminated to all turbine-generators at a single point, rather than having to implement filters, excitation supplemental control or SVC/STATCOMs at all potentially affected units. In essence the control strategy of the TCSC makes the device appear inductive at torsional modal frequencies thereby eliminating the network resonance at torsional frequencies [33], [34], [35]. Often only part of the series capacitor is made into a TCSC [33], this reduces the total cost of the complete installation. In such cases, the resonance is not completely eliminated, since part of the series capacitor is still a fixed capacitor, however, the resonance is shifted far enough to avoid interaction with any of the torsional modal frequencies. The application, however, does require careful study to ensure that the proposed final configuration will be effective for all nearby units.

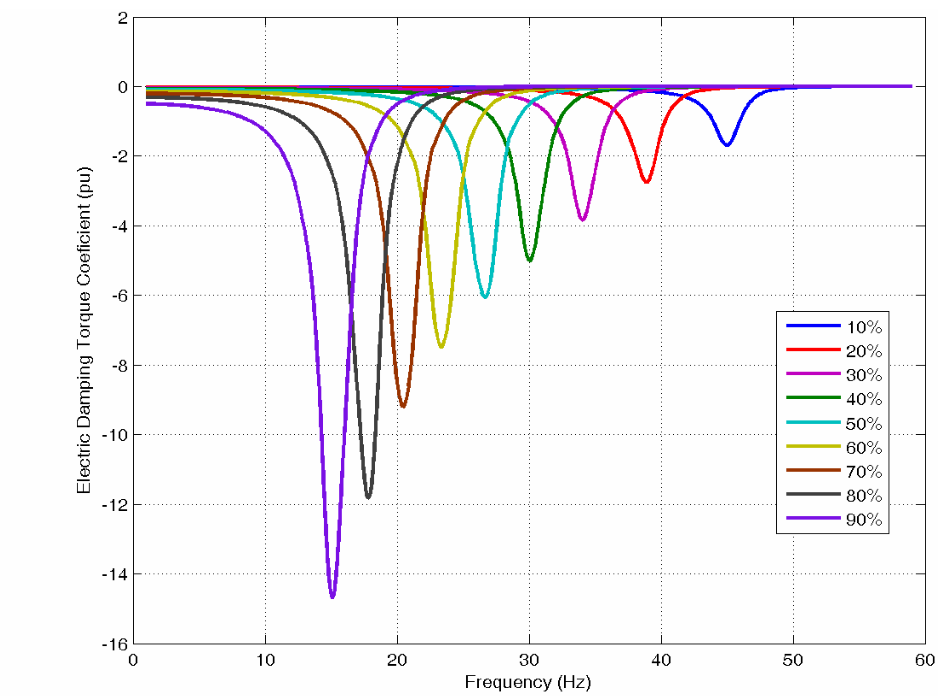


**Figure C-1**
**Electrical damping torque plots for a generic machine feeding a radial 500-kV transmission line that is series compensated.**

# D

# METHODS FOR SCREENING AND DETAILED ANALYSIS OF DDSO

The most widely accepted screening tool for DDSO is that first presented in [27]. The screening method is based on the following equation:

$$UIF = \frac{MVA_{HVDC}}{MVA_{Gen}}\left(1-\frac{SC_{Gout}}{SC_{Gin}}\right)^2 \qquad \textbf{Eq. D-1}$$

where $MVA_{HVDC}$ is the rating of the HVDC system, $MVA_{Gen}$ is the rating of the generator under study, and $SC_{Gin}$ and $SC_{Gout}$ is the system short circuit strength at the HVDC commutating bus with and without the generator under study being in service, respectively. The coefficient calculated by equation C-1 is known as the unit interaction factor (UIF). The physical reasoning behind this calculation can be understood as follows. The likelihood that a turbine-generator will interact with an HVDC system is determined by the following factors:

- How close, electrically, the HVDC system is to the turbine-generator and the relative electrical coupling between two.
- The relative electrical rating (size) of the HVDC system compared to the generator.

Equation C-1 captures both of these factors. The first term identifies the relative size of the two components, while the second terms determined the relative electrical coupling between the two. For example, for a purely radial case (i.e. HVDC is radially fed by a power plant) the short circuit ratio $SC_{Gout}/SC_{Gin}$ is zero and thus the UIF is equal to 1 times the ratio of HVDC to generator rating, while for a distant generator the ratio $SC_{Gout}/SC_{Gin}$ is approximately equal to 1 and thus UIF approaches zero. This is what we would expect. Based on experience, for conventional HVDC, a more detailed analysis is warranted if a credible system condition is found that result in a UIF of 0.1 or greater. Note that a UIF of 0.1 or greater simply indicates that significant electrical coupling exists between the HVDC converter and the turbine-generator, and by itself is not necessarily an indication of detrimental interaction. For example, as shown and discussed in detail in [14], for modern voltage-source converter technologies one can encounter scenarios where the UIF is greater than 0.1 and the impact of the converter is to enhance rather than degrade torsional damping. Thus, this screening tool is simply a means of identifying if more detailed studies are needed. If based on UIF calculations a strong coupling exists between the HVDC system and nearby generators, then it is prudent to perform detailed studies as described in the paragraphs below. This is common practice by the leading HVDC manufacturers when installing new dc transmission systems. It is also worth noting that based on this approach the solution to the problem of DDSO is in filtering and providing supplemental damp control loops in the HVDC control system to mitigate negative interaction at the torsional modal frequencies [14]. This is based on experience from the initial incidences of this phenomenon [10], [28]. Since the events at Square Butte [10] and Intermountain Power Project [28], there have been numerous successful implementations of HVDC system around the world (many in close proximity of large power plants). Thus the prudent course of action is to perform the necessary screening analysis to identify if potentially significant interaction exists between the dc converters and nearby turbine-generators and to then performed detailed studies, with the manufacturers cooperation, to identify if mitigation is necessary—the mitigation takes the form of supplemental control design by the manufacturer.

The approach to screening for the potential for DDSO is to:

- First identify all credible transmission contingencies that lead towards a radial configuration between the turbine-generators of concern and the HVDC system.
- List these outages in order of weakest system condition first to strongest (i.e. largest number of lines out first).
- Calculate the UIF for each generator under study for the various credible scenarios identified in 1) and 2). This process then should be repeated for each turbine-generator in close proximity to the HVDC system. If there are multiple units within a power plant, then combinations and permutations of units in and out-of-service should be considered.
- All cases identified with a UIF of greater than 0.1 are then subject to further analysis as discussed below.

If a large number of transmission lines and parallel units have to be taken off line to effect a UIF of greater than 0.1, then the probability and credibility of such a scenario needs to be considered and compared to solutions that may be costly. Typically, for new HVDC facilities, the mitigation methodology is incorporation of filtering and/or supplemental damping control loops into the converter firing controls that become imbedded into the primary controls with redundancy. Thus, failure of the DDSO mitigation control loops would only occur if the main controls fail, thus shutting down the dc system and eliminating the source of DDSO [14]. In this regard, DDSO mitigation is assured and part of the cost of installation if properly investigate and addressed during the design phase of a new HVDC system installation. The more complicated scenario is when introducing a new generating facility in the vicinity of an existing HVDC system. In this case if the need for DDSO mitigation is identified, it could potentially require refurbishing the existing HVDC control system and thus be a costly exercise.

## DDSO Due to Shunt Power Electronic Devices Such as SVC and STATCOM

Static Var compensators (SVC) can also interact with turbine-generator torsional modes. However, to our knowledge there has never been a recorded incident of damage to the shaft of a turbine-generator due to such a device. If properly tuned, an SVC (or STATCOM) can be effectively used to mitigate phenomenon such as SSR [9]. Although conceptually the UIF factor may also be used as a screening tool to identify the potential for interaction between an SVC/STATCOM and a turbine-generator, it was not developed for this purpose. Specifically, in the case of an SVC a UIF significantly less than 0.1 can still result in significant interaction (for example, in the case of some turbine-generators which use SVCs within the power plant substation for mitigating SSR, the SVC rating is as much as twenty times less than the turbine-generator, i.e. a UIF of 0.05 or less). In general, detailed DDSO analysis (as described below) should be performed for large SVC/STATCOM installations that are within one or two buses of power plants. Typically, however, modern SVC designs do not have a detrimental effect on the torsional modes [13].

## Detailed DDSO Evaluation

The approach for detailed analysis of DDSO is that presented in [27], [11], [14] and [13]. The objective is be able to illustrate that the interaction with the nearby generating units is not likely to destabilize their mechanical torsional modes. The inherent mechanical damping of the torsional modes is determined by windage, steam flow in the turbines etc. For the torsional modes to become unstable, the total electromagnetically induced damping torque must be negative and large enough to eliminate all of the inherent mechanical damping on the shaft. Thus, for the purposes of DDSO analysis, it is sufficient to show that the electrical damping torque induced on the shaft of each unit (over the frequency range of concern) is not adversely affected by the introduction of the HVDC (or SVC). If, however, the electrical damping is significantly reduced or made negative in the range of model frequencies of concern, then controls and/or filtering has to be introduced to eliminate this – such control design of course needs to be done with care as it may exhibits a compromise between torsional damping and general control performance (i.e. power regulation response time for the dc system or voltage regulation response for the SVC). Typically there is no need to determine the mechanical damping component on the shaft of the machines. Electrical damping torque calculations, in the frequency range of interest, alone are sufficient to demonstrate system performance.

Depending on the apparent network impedance (looking into the system from the generator) and the dynamic response of the nearby HVDC converter (or SVC), a perturbation in machine speed will result in a perturbation in terminal voltage and generator current, which then translates into a change in electromagnetically induced torque on the generator shaft [13]. This can be expressed mathematically as:

$$\Delta Te = F(s)\Delta\omega \qquad \textbf{Eq. D-2}$$

where F(s) is the transfer function incorporating the net effect of the frequency response of the generator and transmission system and devices. The variable $\Delta\omega$ represents speed perturbation and $\Delta Te$ perturbation in electrical torque. This transfer function will have a given magnitude and phase at each frequency, or a complex value in polar form. This complex value can then be expressed in terms of its real and imaginary parts, that is:

$$\Delta Te = F(s)\Delta\omega \qquad \textbf{Eq. D-3}$$

where

$$D(\omega) = \mathrm{Re}\{F(s)\}|_{s=j\omega}$$

$$S(\omega) = \mathrm{Im}\{F(s)\}|_{s=j\omega}$$

The real part of the transfer function, D(ω), is a component in phase with the initial speed perturbation. The imaginary part, S(ω), is a component in quadrature (90 degrees out of phase) with speed and in phase with rotor angle [29]. If D(ω) is positive at any given frequency this represents positive electrical damping, while a negative component of electrical torque in phase with speed represents a destabilizing effect, or negative damping. The quadrature component has the effect of restraining rotor angle movement, and thus is called the synchronizing torque component. Here we are interested only in the damping torque component, i.e. D(ω).

To calculate the transfer function a model needs to be developed of the electrical network, the transmission device(s), such as HVDC, and the power plant. The model needs to faithfully represent power electronic firing controls (explicitly), the delays associated with the valve firing that can be significant for DDSO calculations should also be included. Typically, this analysis is down in 3-phase using programs such as EMTP-RV, MATLAB Simulink® or EMTDC/PSCAD®. A sinusoidal speed perturbation signal is injected into the machine model and the resulting perturbation in electrical torque is measured, with the machine shaft dynamics disabled. The transfer function from speed to electrical torque is then calculated. The real part of the transfer function is then extracted through signal processing to determine the damping torque. Thus, the component of electrical torque perturbation (ΔTe) in phase with speed perturbation (Δω) is extracted. The calculation is repeated over the frequency interval relevant to the torsional frequencies of concern, and the results are depicted as a family of curves showing electrical damping versus rotor frequency, with a separate curve for each studied system condition. Since the primary interest is in a small signal response, the sinusoidal speed perturbation injected into the model is of relatively small magnitude. Figure D-1 shows an example result from such analysis. In this example we see that the SVC generally has no detrimental impact of torsional damping, and in fact is enhancing damping under some conditions.

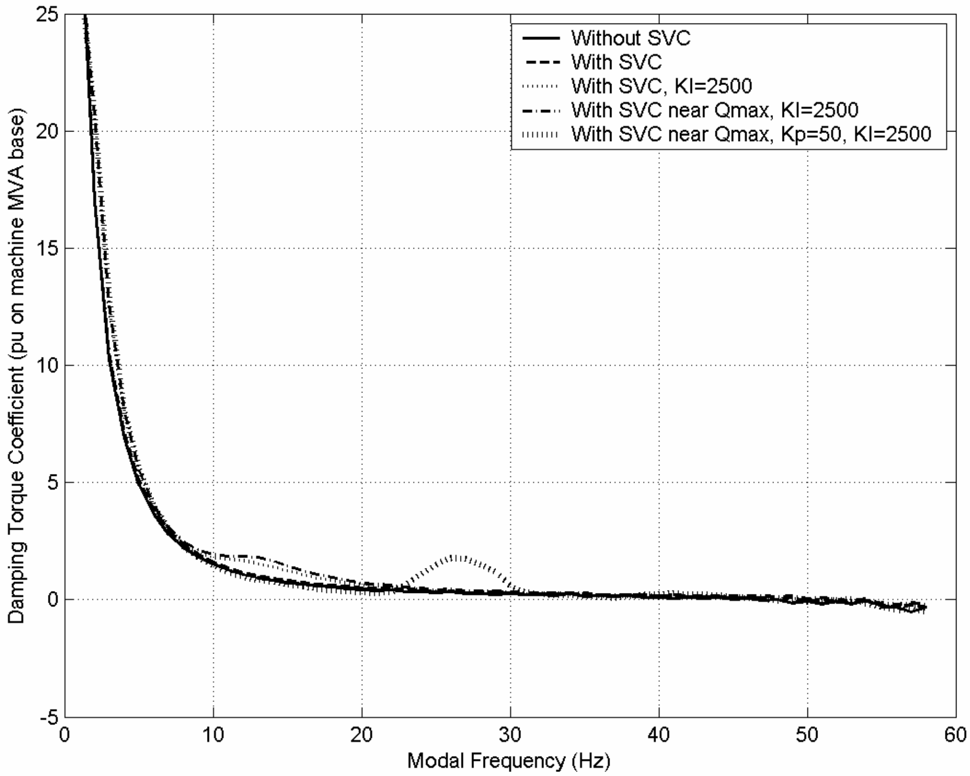


**Figure D-1**
**Example results of a detailed DDSO damping torque calculation analysis. This figure is reproduced from reference [13], with permission from IEEE. (© 2006 IEEE).**

# E

# GENERIC MODEL FOR STUDYING GENERAL TORSIONAL INTERACTION

Figure E-1 shows a one-line diagram of the system model developed. The following general comments are pertinent:

- The two 1800-RPM units have an assumed rating of 1,500 MVA. The generator electrical data is based on actual data for 1800-RPM units of a similar size. The mechanical data is based on an actual anonymous turbine-generator shaft for a 1800-RPM unit of similar size. The unit has been modeled with a typical static exciter and a PSS, thought the PSS is disabled. The data is presented in Appendix A.
- The 3600-RPM unit is based on the IEEE Benchmark case [4]. The data is provided in Appendix B.
- All 500-kV lines assume a 954 ACSR conductor, with a horizontal configuration at 42 ft spacing between phases, and a triple-conductor bundle with 18-inch spacing between conductors in the bundle (triangle configuration)—this is based on a typical US tower/line design in the Western System:

  $R1 = 0.0981\ \Omega$/mile $X1 = 0.581\ \Omega$/mile and $C1 = 0.019\ \mu F$/mile ($R0 = R1 \times 9$, $X0 = X1 \times 3$ and $C0 = C1 \times 0.6$)
- All 230 kV lines assume a typical horizontal, 22 ft span, single bundle 954 ACSR conductor:

  $R1 = 0.099\ \Omega$/mile $X1 = 0.798\ \Omega$/mile and $C1 = 0.0141\ \mu F$/mile ($R0 = R1 \times 9$, $X0 = X1 \times 3$ and $C0 = C1 \times 0.6$)
- All the power transformers (500/230 kV and GSUs) are assumed to have an impedance of 18% on their FOA rating and an X/R of 85 (X= 0.18 pu, R=0.0021 pu). The GSUs for the 1800-RPM units are assume to have an FOA of 1,550 MVA, for the 3600-RPM 900 MVA and for the substation transformers (500/230 kV) 1,300 MVA. The GSUs are assumed to by Y ground—Delta (delta on generator side) and the substation transformers were assumed to be Y ground—Y ground.
- The line from Bus 9 to 5 is assumed to be a 200 mile 500-kV line. A series capacitor compensating for 50% of this line has been added at the Bus 9 end with an assumed 1,500 A RMS continuous rating and with metal-oxide varistor (MOV) protection at 2.1 pu (a typical GE varistor characteristic has been assumed). Sensitivity analysis will clear be needed here on the value of series compensation and the level and type of protection (i.e. pure MOV versus gapped, fast bypass breaker etc.).

## Equivalent Sources

The equivalent sources S1 to S4 have been set to typical short-circuit strengths of 500-kV substations in the US system.

S1 = 0.0008 + j0.01 pu

S2 = 0.0002 + j0.002 pu

S3 = 0.006 + j0.003 pu

S4 = 0.0005 + j0.005 pu

All values are on 500 kV, 100 MVA, and the zero sequence impedance was assumed to be double the positive sequence value.

## Power Flow Solution

The 1,800 RPM units are 0.9 power factor (pf) units while the 3,600-RPM unit is a 0.85 pf unit. Thus, the initial power flow solution has 1,350 MW generated by each of the two 1800-RPM units and 760 MW begin generated by the 3,600-RPM unit. All 500 and 230-kV network voltages are between 1.02 to 1.06 pu (two load buses are down around 0.96 to 0.97 pu). The power flow was varied for various simulation and sensitivity cases. The Tables below show the generator output and system bus voltages—the generator terminal voltages and the equivalent source voltages were kept constant for all simulations.

## Time Domain Simulations

All time domain simulations were performed using the EMTP-RV® program. All simulations, unless otherwise specified, were run for 1 second at a 5 micro-second integration time step. The lines were modeled as continuously transposed distributed parameter lines.

**Table E-1**
**Node Voltages**

| Sr.No. | Bus | V(pu) | Rated kV |
|---|---|---|---|
| 1 | Bus1 | 1.04 | 500 |
| 2 | Bus2 | 1.05 | 500 |
| 3 | Bus3 | 1.05 | 500 |
| 4 | Bus4 | 1.01 | 500 |
| 5 | Bus5 | 1.05 | 500 |
| 6 | Bus6 | 1.03 | 500 |
| 7 | Bus7 | 0.97 | 500 |
| 8 | Bus8 | 1.05 | 500 |
| 9 | Bus9 | 1.07 | 500 |
| 10 | Bus10 | 1.05 | 500 |
| 11 | Bus11 | 1.06 | 230 |
| 12 | Bus12 | 1.04 | 230 |
| 13 | SM1 | 1.04 | 25 |
| 14 | SM2 | 1.04 | 25 |
| 15 | SM3 | 1.04 | 25 |

**Table E-2**
**Generator Output**

| Unit | P(MW) | Q(Mvar) |
|---|---|---|
| SM1 | 1350 | 78.9 |
| SM2 | 1350 | 78.9 |
| SM3 | 760 | 214 |

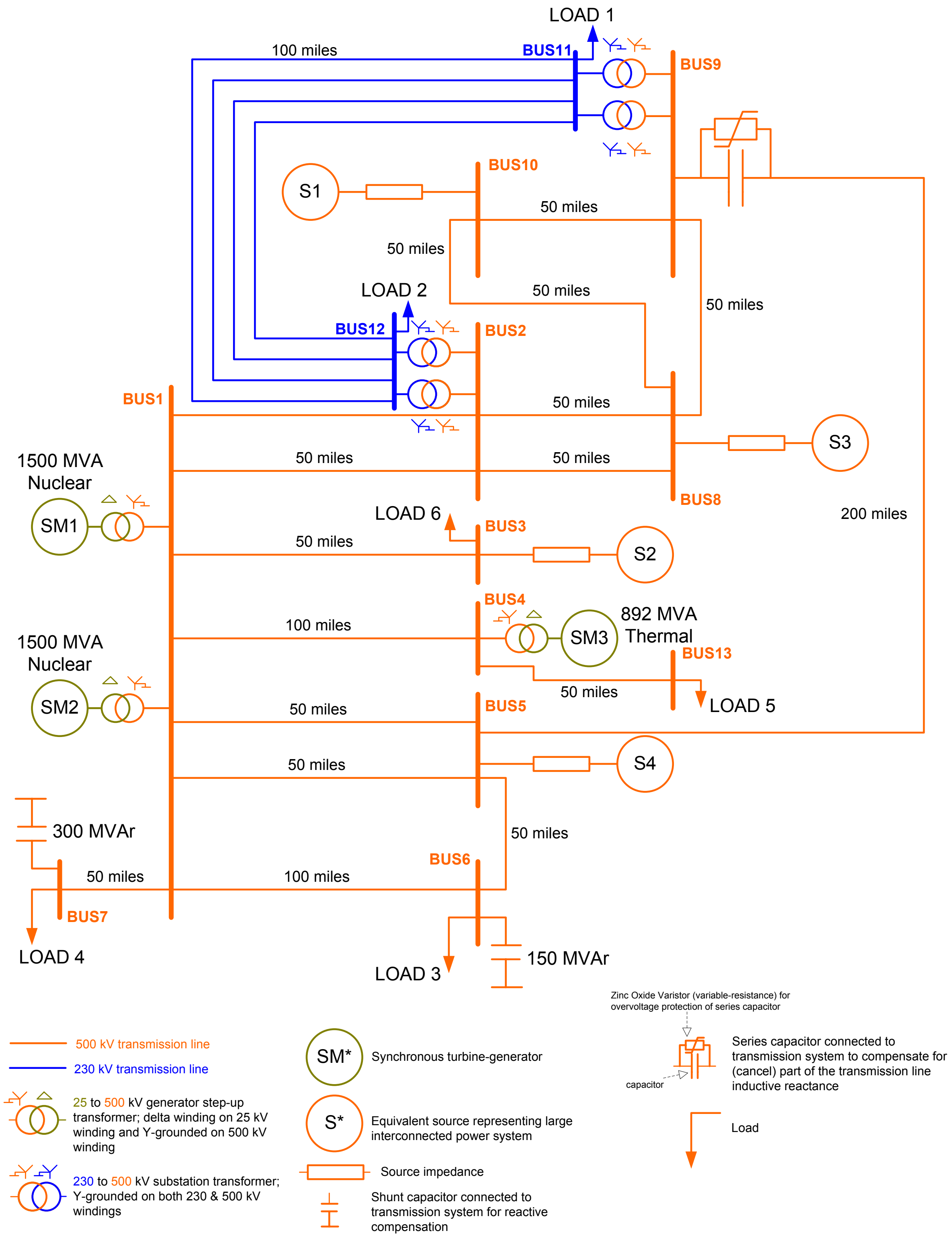


**Figure E-1**
**System Model**

# F
# SAMPLE PLOTS OF SIMULATION RESULTS

**Terminal Voltage** is the voltage at the machine terminals in pu on machine rating (25 kV rms).

**Stator Current** is the current being injected by the machine at its stator winding terminals in pu on machine rating.

**Te**—Electrical Torque in pu on machine MVA base.

**Pe** —Electrical Power in pu on machine MVA base.

**Tm***—Mechanical torque on shaft * between adjacent masses in pu on machine rated torque (rated torque = rated power / rated speed).

**Plots for 3-phase to ground fault at the terminals of machine SM1**—all plotted variables are for machine SM1

**Plots for 3-phase to ground fault at the terminals of machine SM1**—all plotted variables are for machine SM1

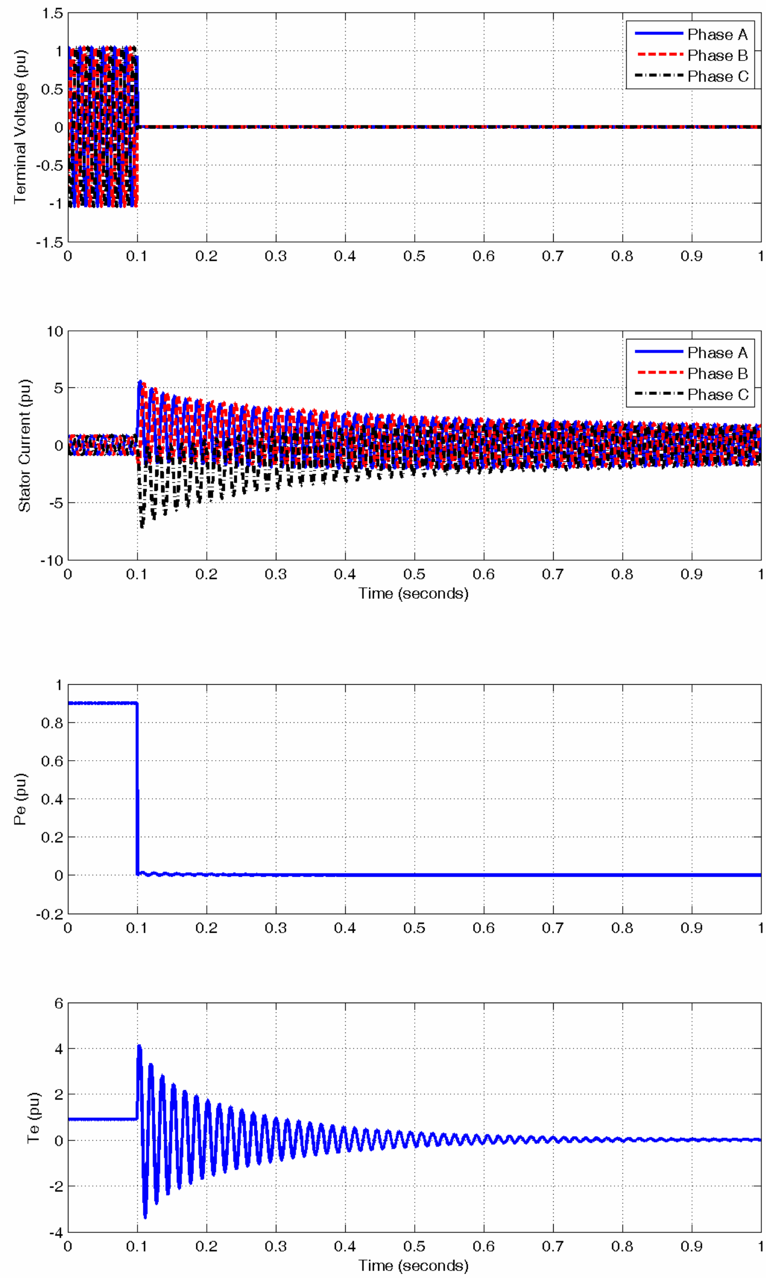


**Figure F-1**
**Plots for 3-phase to ground fault at the terminals of machine SM3 —all plotted variables are for machine SM3.**

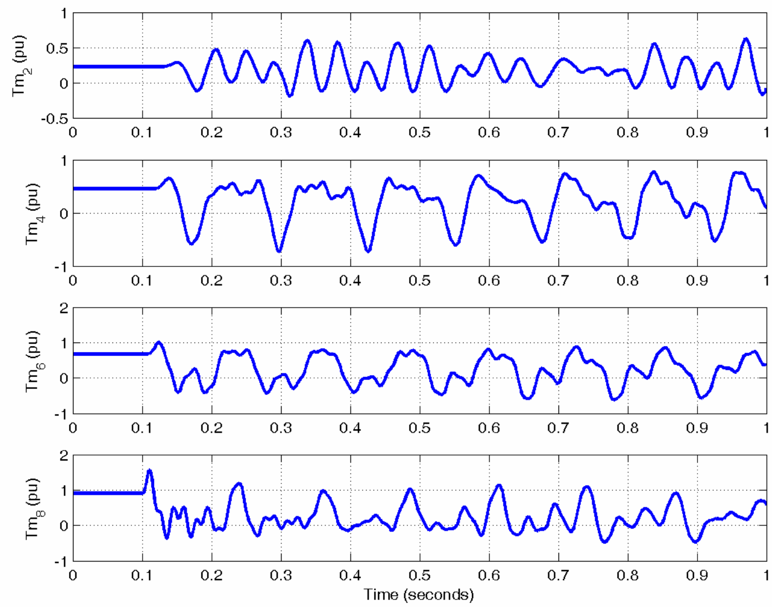


**Figure F-2**
**Plots for 3-phase to ground fault at the terminals of machine SM1—all plotted variables are for machine SM1.**

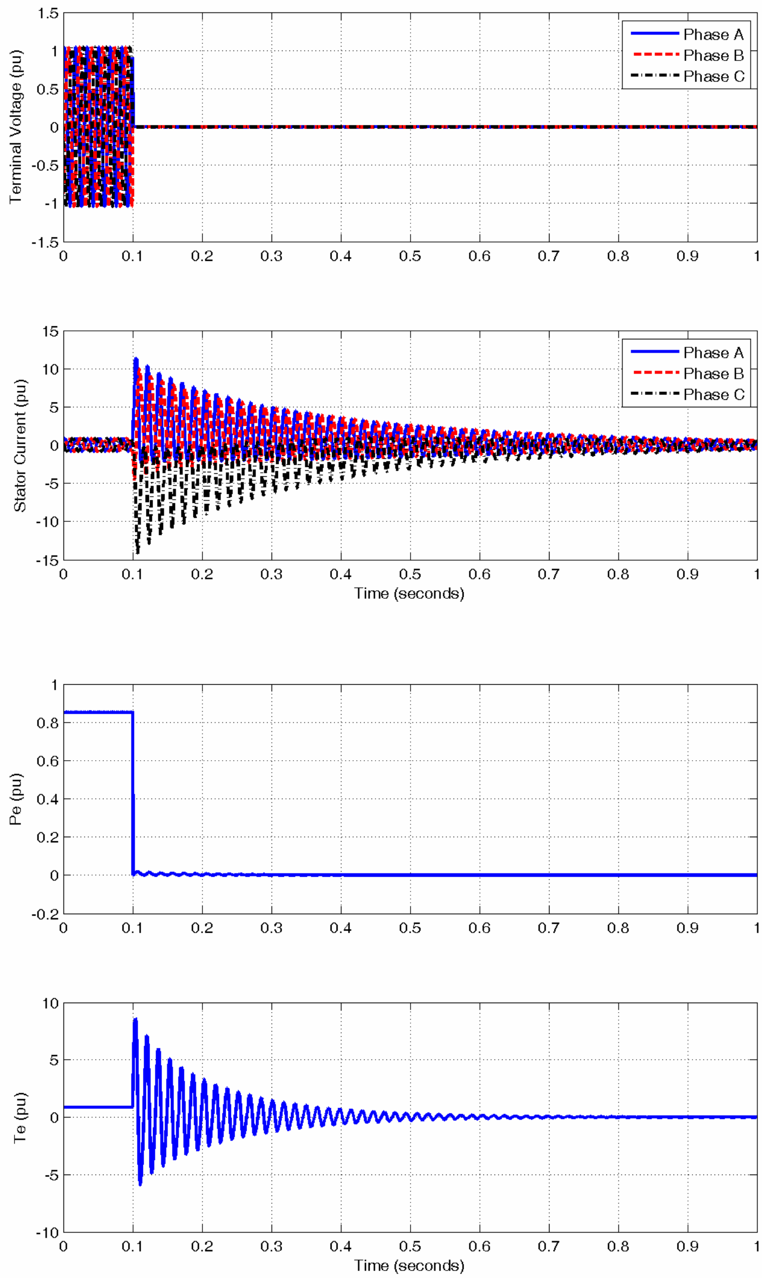


**Figure F-3**
**Plots for 3-phase to ground fault at the terminals of machine SM3—all plotted variables are for machine SM3.**

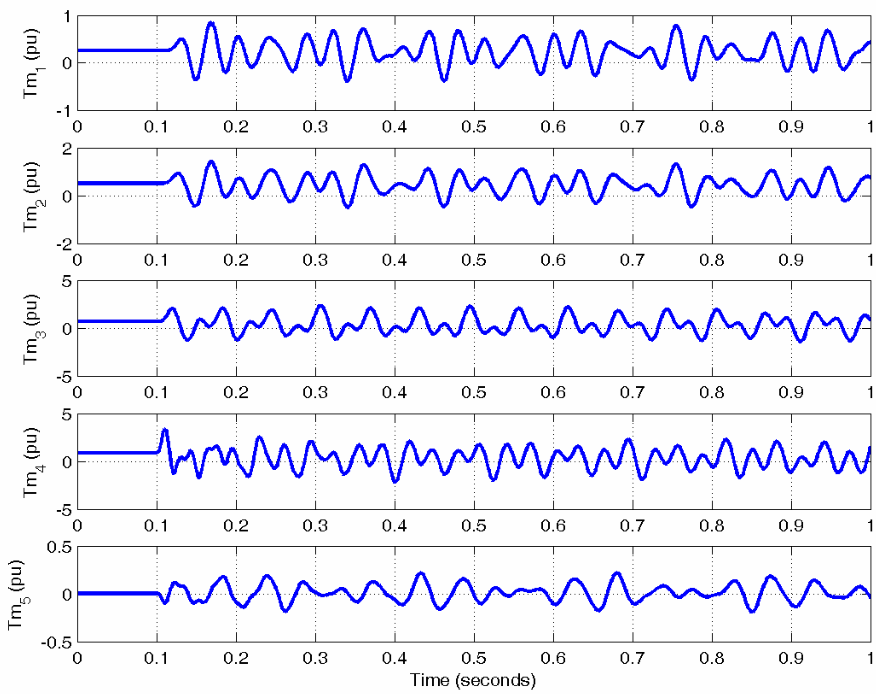


**Figure F-4**
**Plots for 3-phase to ground fault at the terminals of machine SM3—all plotted variables are for machine SM3.**

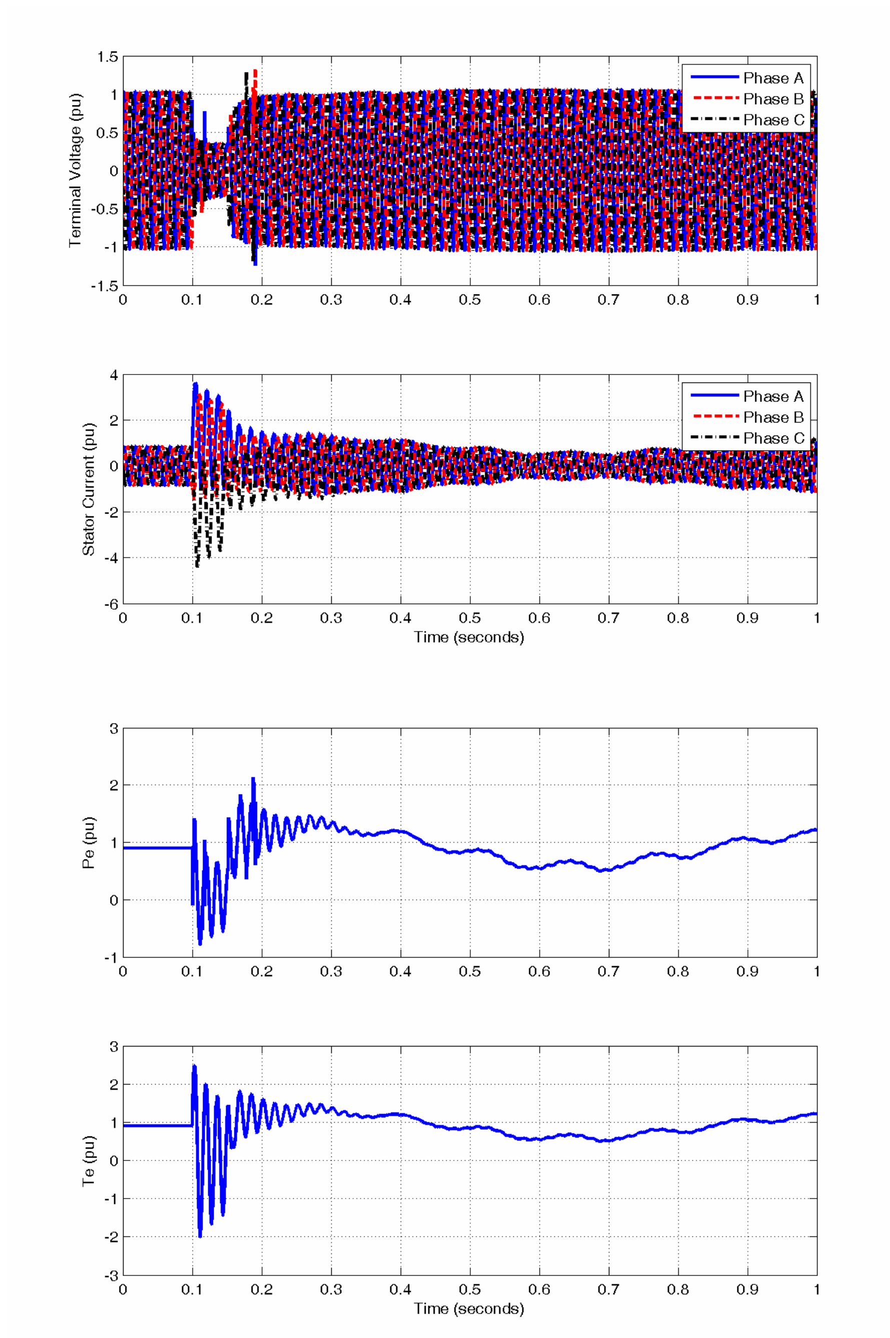


**Figure F-5**
**Plots for 3-phase to ground fault at bus 1 end of line 1-2, followed by clearing the line in 3 cycles. All plots for variables of SM1.**

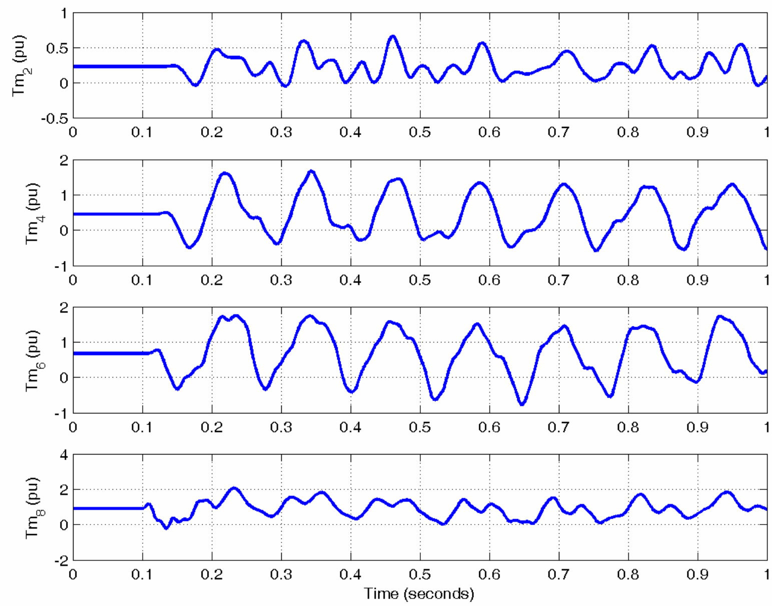


**Figure F-6**
**Plots for 3-phase to ground fault at bus 1 end of line 1-2, followed by clearing the line in 3 cycles. All plots for variables of SM1.**

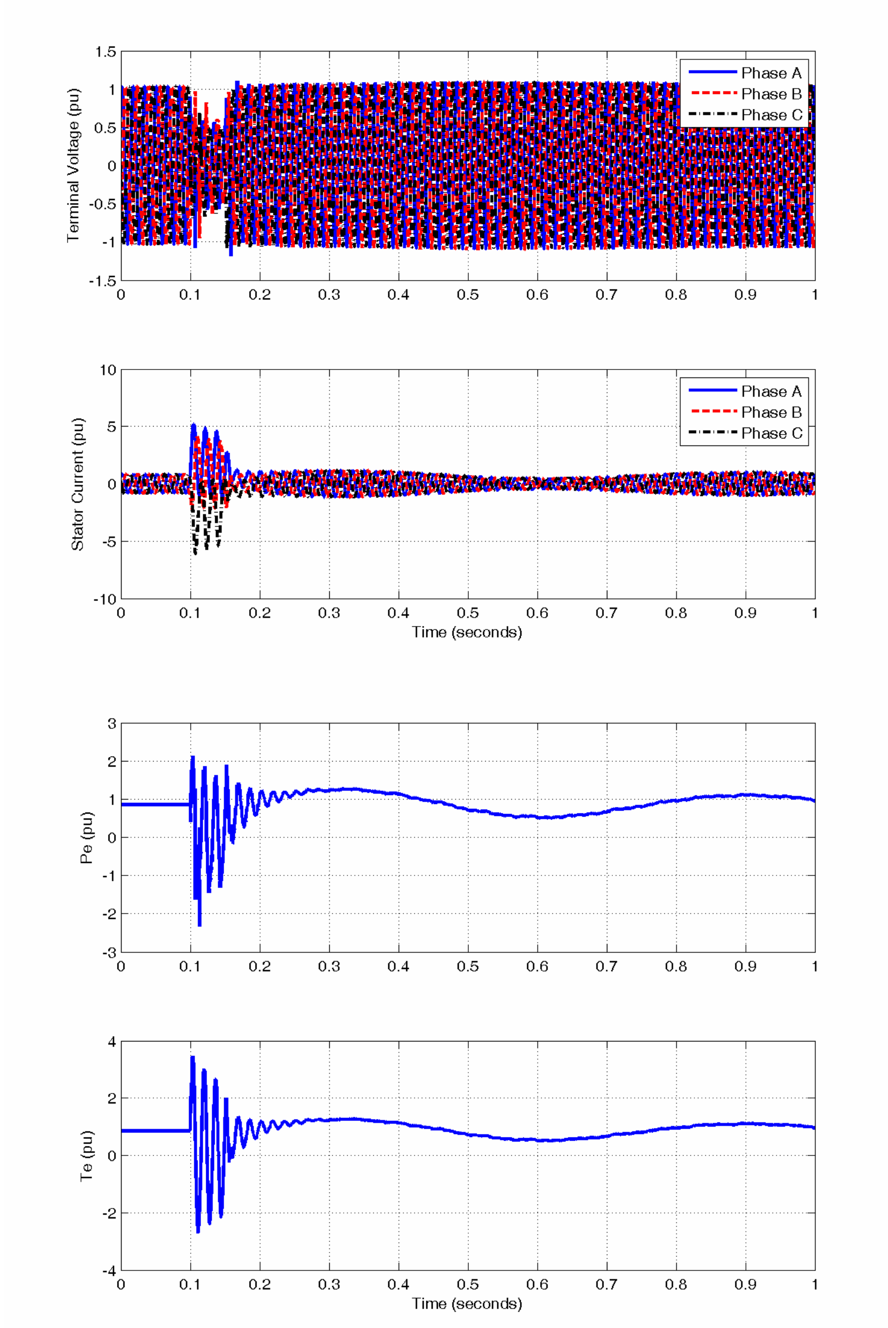


**Figure F-7**
**Plots for 3-phase to ground fault at bus 4 end of line 4-13, followed by clearing the line in 3 cycles. All plots for variables of SM3.**

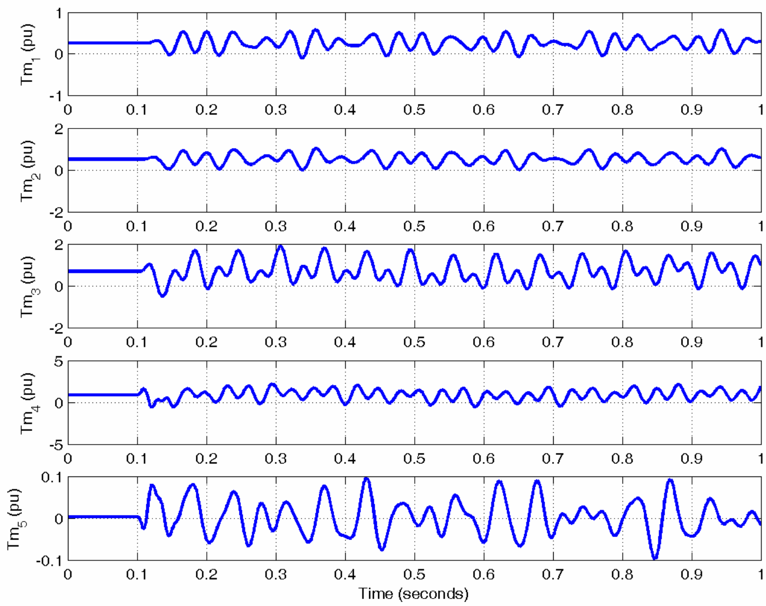


**Figure F-8**
**Plots for 3-phase to ground fault at bus 4 end of line 4-13, followed by clearing the line in 3 cycles. All plots for variables of SM3.**

# G
# SELF ASSESSMENT GUIDE

The following questions should be used to determine if the plant/unit is vulnerable to torsional interaction

1. Do you know the natural torsional frequencies of the current configuration of the turbine-generator shaft? Have the calculated values been confirmed by measurements? Is there any natural torsional frequency that can be excited by torque on the generator rotor within a 2-Hz window of double the power frequency (i.e. 120 Hz in 60-Hz systems and 100 Hz in 50-Hz systems)?
2. Does the plant have a digital fault recorder to monitor transients "entering" the plant?
3. Do plant operating procedures eliminate the risk of out phase synchronization angles larger than 15 electrical degrees?
4. Do the transmission lines employ series capacitors? If so are these lines connected to the plant bus or one or two buses away from the plant?
5. Is the unit frequently exposed to severe faults in the transmission system near (electrically) the plant? If so, is appropriate shaft inspection performed during subsequent outages?
6. Does the transmission operator employ high speed reclosing? If so, is high speed reclosing applied on lines connected to the plant? If high speed reclosing is employed one or two buses away from the plant, does the plant know the number of reclosing attempts and the delay times between fault clearing and reclosing? Have studies or tests been performed to assure that the turbine generator shaft will not see fatigue damage from high speed reclosing?
7. Is the plant in the proximity of an HVDC terminal, steel mill, arc furnace, static var compensator, or any other systems employing large power electronic devices and controls?
8. Have precautions being taken by the transmission system operator (such as employing lockouts on reclosing lines when there is excessive load angle across the closing breaker) to assured that transmission line switching operations will not provide sudden changes in generator power that exceed 50% of its rating?

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