

Turbine Generator Synchronization – Two Case Studies

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This article presents two case studies of increased vibrations associated with load dispatch and removal from gas turbine-driven synchronous generators during electrical supply synchronization. The first case involves a classical uneven air gap fault due to a loose foot on the generator. Such faults are readily detected from the $2\times$ line frequency associated with an electrical defect source. Another case involves unusually high transient vibrations during synchronization and not widely reported in the literature. Vibration levels increased during synchronization which, under full load conditions, remained high and resulted in a unit trip due to excessive vibration levels. At partial-load conditions, the high-transient vibrations dropped back down to pre-synchronization levels. Dominant vibration frequency was at $1\times$ synchronous frequency (and not the classical $2\times$ line frequency). This fault was not due to the generators themselves but due to defects involving the synchronization process with likely out-of-phase synchronization.

Turbine generator sets are used in power generation and are connected within a power grid system typically to the electricity grid on a district or a stand-alone power system such as on an offshore oil and gas facility. Common vibration problems in turbine generators often relate to mechanical faults associated with mass unbalance, misalignment and rubs. Problems originating from the generator are less frequent and can often be misdiagnosed by plant operators and third-party personnel. This article presents two case studies of turbine generator vibration problems originating from synchronization of the generator with the electrical power system to which the units were dispatching power.

Synchronous generators convert mechanical energy from a prime mover (typically a gas or steam turbine) to alternating current (AC) electric energy. A direct current (DC) is applied to the rotor winding of a synchronous generator to produce a rotor magnetic field. The prime mover rotates the generator rotor to induce a rotating magnetic field in the machine. A three-phase set of voltages is generated in the stator windings by the rotating magnetic field. For electrical power to be dispatched into the electricity grid (which is at a higher electrical potential), the disconnected generator has to be synchronized into the power network grid. Connecting a synchronous generator to the power system is a dynamic process, requiring the coordinated operation of many components (electrical, mechanical and often human). The goal is to connect the spinning generator to the system when the generator matches the system in voltage magnitude, phase angle and frequency.

Turbine Generator and Synchronization Faults

Problems with turbine generators may be classified as mechanical or electrical/electromagnetic in nature. Typical mechanical vibration problems, as in any rotating machine, are mass unbalance, misalignment and rotor rubs. Mass unbalance occurs due to imbalance in the rotor assembly (from blades of non-identical mass distribution) and for in-service machines usually from lost parts or foreign object damage (FOD).

Such mass unbalance results in high overall vibrations and is easily identified from the increase of the synchronous $1\times$ RPM vibration component in the vibration spectrum as well as from the phase relationships of vibration measured across the turbine generator set. Misalignment occurs from inadequacies in correct alignment of the rotors across the coupling. With in-service machines, this is more often induced via pre-loads due to thermal expansion and problems in the supports instead. Alignment-related faults are easily identified from the synchronous $1\times$ RPM and $2\times$ RPM

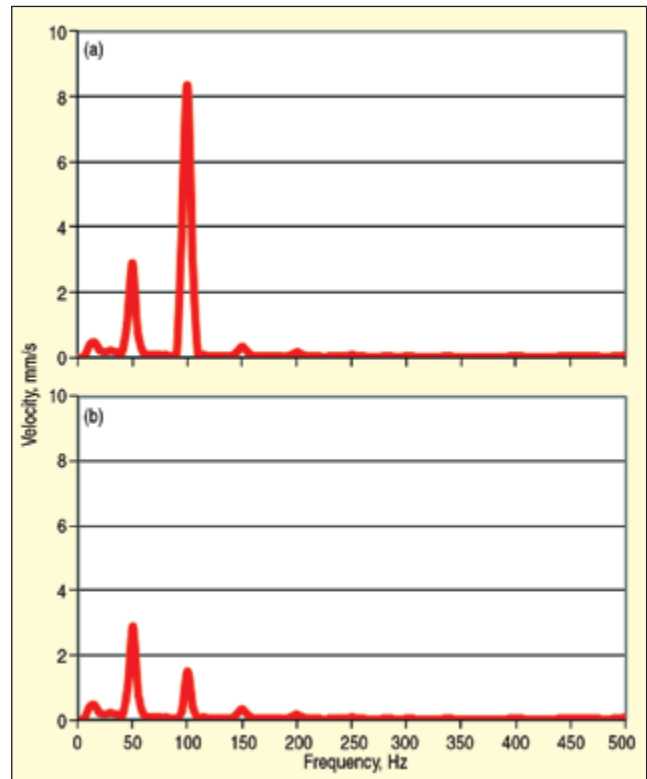


Figure 1. Vibration spectrum generator drive end bearing: (a) with load dispatch; and (b) immediately after power removal.

vibration components in the vibration spectrum as well as from the phase relationships of vibration measured across the turbine generator set. Rotor rubs and bearing failures are often the result of excessive vibrations from mass unbalance and/or misalignment. Another occasional problem with in service equipment can be from loose mounting feet.

Electrical problems are associated with unequal air gaps that pull the rotor more strongly at the location of least gap and cracked or broken rotor bars that move and change the rotor balance under the effects of a magnetic field and centrifugal force.¹ Stator problems, eccentric rotors and phasing problems result in high vibrations at $2\times$ electrical AC frequency ($2\times$ line frequency). For synchronous generators this $2\times$ line frequency is also the $2\times$ RPM rotational frequency. Since electrical problems are less frequent, the initial suspect of this $2\times$ synchronous component is a misalignment or preload fault. While an experienced vibration analyst can easily distinguish the mechanical and electrical fault when power is removed, the sequence of events during synchronization is measured in seconds, and differences in vibration behavior could be easily missed. If the problem is electrical in nature, the excessive vibration and particularly the $2\times$ line frequency component would disappear immediately when power is removed. If the problem is mechanical, the vibration components ($2\times$ RPM) would decay in proportion to the speed. An example of this diagnostic process using real-time station DCS (distributed control system) monitoring data and FFT spectrum comparison is presented in Case Study 1.

A less frequent problem relates to faults arising from the synchronization process. Electric power systems consist of an interconnection of multiple units of synchronous generators

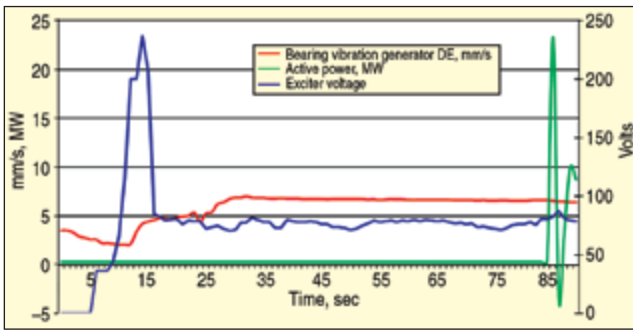


Figure 2. Plot of bearing vibrations with exciter voltage and active power during synchronization.

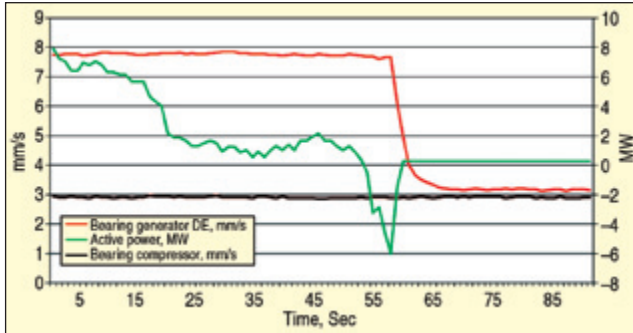


Figure 3. Plot of bearing casing vibrations with active power during load removal and coast down.

operating in parallel. The generators are connected by electrical power transmission cables supplying the power network system. The disconnected generator can be paralleled when the generator voltage and network voltage are momentarily in phase. The failure of the synchronizing procedure results in an out-of-phase synchronization. Different causes of this can be due to:

- Failure in wiring during commissioning and maintenance
- Delay during breaker closure
- Flash-over in breaker contact
- Wrong setting of synchronizing system

Extensive papers have been published related to electrical stability and issues related to voltage instability in power network systems from the perspective of power system dynamics and stability.^{2,4} A review paper on the phenomena and its problems was for example published by Cutsem.² Vibration problems during synchronization of power generators however have not been widely reported; this is even less so for in-service machines. Chen *et al.*³ reported concerns of loss of life in a turbine generator following a faulty synchronization incident. A unique problem of time-varying vibrations during synchronization not widely reported in the literature is presented in Case Study 2.

Case 1 – Classical Behavior

This case involved a 100-MW gas turbine used in a combined-cycle power plant. Rotor speed was 3000 RPM for electrical power generation (50 Hz). Relatively high vibrations were reported for the gas turbine generator. The station monitoring sensors showed casing vibration levels on the drive end bearings to be on the order of 7 to 8.5 mm/s. The generator nondrive-end bearings had casing vibrations in the order of 1 mm/s, and on the turbine compressor bearing, 3 mm/s. Vibration spectrum showed a high vibration component at 100 Hz (see Figure 1). As condition-based monitoring (CBM) practices usually do not involve phase measurements or correlation of phase relationships across the machine, the 100-Hz vibration component was initially diagnosed as 2× RPM, and a misalignment was immediately suspected by the CBM personnel. A work order was issued for a re-alignment of the turbine generator set. It was at this stage where the more experienced maintenance manager, who was not convinced that a misalignment could possibly occur on an operational unit, requested a more detailed investigation.

Subsequent vibration measurements by the authors confirmed high casing vibrations on the drive end generator bearing; typically

8 mm/s, as compared to 1 mm/s on the nondrive end generator bearing. Turbine vibration as measured on the compressor side was 3 mm/s. The drive-end generator bearing vibration was dominated by the 100 Hz component, which could either be the 2× RPM or 2× line frequency harmonics (see Figure 1a).

Phase relationships of the 1× RPM vibration component did not demonstrate any of the 180° out of phase characteristics across the coupling (turbine and generator shafts) that was to be expected of misalignment. Vibration measurements during coast-down and run-up were then undertaken to confirm vibration characteristics without electrical power generation. Vibration amplitude of the generator bearing (drive end) upon power removal from the electrical power grid showed an immediate drop and was confirmed by the absence of the high 100-Hz vibration component (see Figure 1b).

A better validation of the high vibrations with electrical excitation was obtained from comparing plots of exciter voltage and active power of the generator against vibration levels. These data were extracted from the plant DCS in the control room. Data from the DCS are usually overwhelming with numerous process data continuously logged in real time. Data at the time of synchronization (during run-up) and removal from the electricity grid (during coast-down) were extracted from the DCS data history. Figure 2 shows a gradual increase in overall vibration levels of the generator bearing upon application of the exciter voltage approximately 60 seconds before synchronization.

Validation was obtained during power removal and machine coast-down when generator vibrations immediately dropped from 8 mm/s to 3 mm/s at the instance of power removal. Vibrations on the turbine (measured on the compressor bearing casing) remained unchanged at 3 mm/s during the load removal process and thereafter at start of coast down. At this point, generator speed was still at 3000 rpm, shown in Figure 3. Any 2× RPM vibration component associated with misalignment would persist if the fault was mechanically induced. Even though there were initial reservations on possible faults in the generator, subsequent inspection on the unit confirmed a loose foot on the generator. This loose foot resulted in a variable air gap between the stator and rotor. This example illustrates the benefit of correlating electrical parameters (active power generated from the generator and exciter voltage) against measured vibrations to identify the root cause of excessive vibration.

Case 2 – Unusual Time Oscillating Vibration

While Case 1 is a classical example of an electrical fault originating from a mechanical installation degradation problem (loose foot) with classical symptoms of 2× line frequency dependent on the electrical power excitation, Case 2 illustrates an unusual vibration behavior not widely reported in the literature.

This case involves three unit gas turbines generators (3 × 1500 kW) in an offshore oil production platform and floating facility in the South China Sea offshore Malaysia for power generation into a centralized electricity supply network. The gas turbine drives the generator via a step-down gearbox. The turbine generators had a history of trouble-free, long-term operation. There had been a recent recurring unusual vibration behavior of the units where occasional high vibrations were reported on the generator exciter shaft vibration monitors (even on the unit that was not operating). Under full load, units tripping due to excessive vibrations had occurred. These units typically deliver 65% electrical load under normal operations with full-load dispatch only when all facilities (oil transfer pumps) were in full operation.

Tests for different combinations of unit operations were carried out. With only two units operating, the spinning units each operated at rated capacity (~1400 kW each) to dispatch approximately 65% of the entire power system load. Tests with all three units spinning required operation of the individual units to be operated at partial load to make up the total system electrical loading (at ~65% of power system capacity).

Casing vibration measurements on the turbine bearing (drive end), gear box bearing (drive end) and generator bearings (drive end and nondrive end) were undertaken under steady-state operations (see Figure 4). Vibration time data for the machines as well as the machine skid and structural deck supporting all three units were

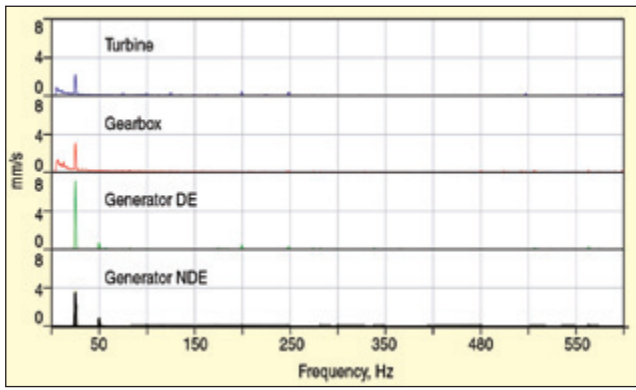


Figure 4. Vibration spectrum of turbine, gear box and generator bearing casings.

also continuously monitored with multichannel data loggers over the entire duration for start up, synchronization and load removal process of unit switch-over and operation combinations. On-board OEM (original equipment manufacturer) overall vibration monitoring data for gear box bearing acceleration and generator shaft displacements (exciter bearing) were available in the control room display. Overall casing vibrations under steady-state operation for the different test combinations are summarized in Table 1.

While vibrations as measured on the casing were significant particularly for Units 2 and 3, these levels were not of major concern. Vibration frequency spectrum under steady-state operation showed dominant spectral peaks at 25 Hz (corresponding to the generator 1× RPM synchronous frequency) and 250 Hz (turbine 1× RPM rotation frequency). The other significant spectral peak was at 460 Hz (1× gear mesh frequency). The second harmonics (50 Hz) of the generator 1× RPM synchronous frequency was insignificant (noted primarily on the generator casing measurements only). This 50-Hz component corresponded to the electrical line frequency of 50 Hz. The other notable peak (occasionally noted in the spectrum) was 225 Hz (9× generator RPM or the lower sideband of the turbine 1× RPM of 250 Hz modulated at the generator RPM).

Synchronization of a third unit into the power system (with two units already operating) resulted in time-varying vibrations on all units, most pronounced on the generator. Results for Unit 2 synchronizing into the power system during Units 1 and 3 operation are presented here. Power dispatch was at approximately 65% of system full-load capacity. (Results were similar with other test cases with different combinations of test units).

At the instance of Unit 2 synchronization, manual readings from the on-board exciter shaft displacement sensor showed increased levels from 1.3 mils p-p to 2.5 mils p-p, and fluctuated with time between 0.2 mils p-p to 3 mils p-p. After approximately 10 minutes, vibration levels stabilized at 1.1 mils p-p. Gearbox casing vibrations remained constant at 2.2 g RMS. A plot of the DCS manual vibration readings versus time is given in Figure 5.

Casing vibration measurements, particularly on the generator drive end and nondrive-end bearings showed increased vibration levels during synchronization and load removal of generator units. Vibration frequency spectrum showed vibration increase at the 1× RPM generator synchronous frequency component. Vibration frequency components corresponding to electrical line frequency and its harmonics were not evident (insignificant). This contradicted expectations of dominant vibration components of 2× line frequency associated with conventional faults of generators and electrical machines (if the faults were originating from the generators themselves). In this respect, since vibration levels were

Table 1. Summary of measured overall casing vibrations, mm/s.

Field Test, ~65% load	Unit 1		Unit 2		Unit 3	
	Turb.	Gen.	Turb.	Gen.	Turb.	Gen.
All on	3.1	2.0	3.4	7.3	3.6	11.0
Unit 1 off; 2 & 3 on	0.6	0.7	2.9	5.7	4.0	11.2
Unit 2 off, 1 & 3 on	0.6	0.7	0.6	1.1	4.7	11.2
Unit 3 off, 1 & 2 on	3.0	2.1	3.4	8.0	0.5	1.1

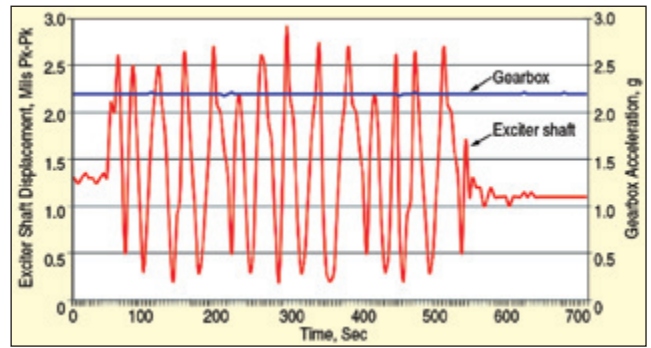


Figure 5. Exciter shaft vibrations and gearbox acceleration DCS readings during synchronization process.

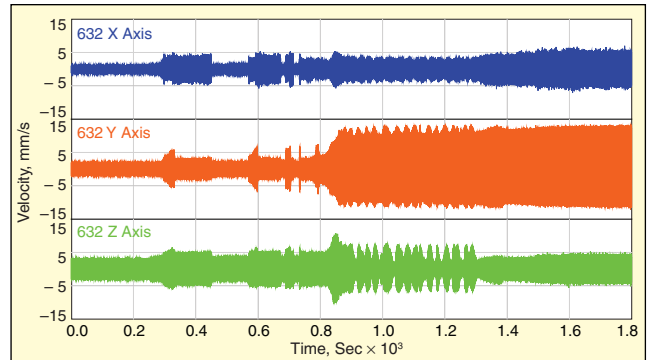


Figure 6. Unit 2 generator 1× filtered vibrations (3 axes) before start-up, start-up, and synchronization.

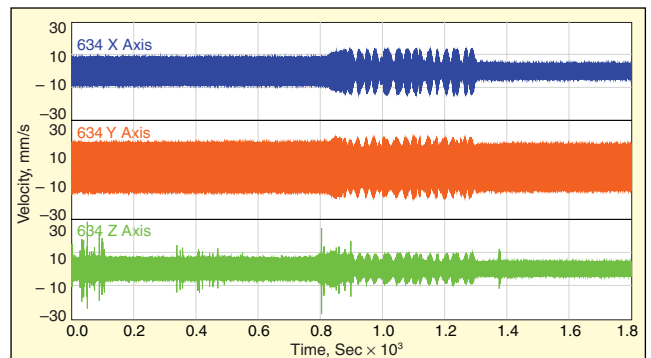


Figure 7. Unit 3 generator 1× filtered vibrations (3 axes) before start-up and during synchronization of Unit 2.

not high (increased) during steady state operation, a reasonable conclusion was that the generators themselves were not faulty.

Overall and filtered 1× synchronous time waveforms from these data were then examined in detail during phases of synchronization and load removal. These time histories showed distinct fluctuations in vibration amplitudes initiated during synchronization that dropped back down to pre-synchronization levels after approximately 10 minutes (for test conditions at 65% of system full load capacity).

Vibration time waveforms for measurements on Unit 2 start-up are shown in Figure 6. The time waveforms showed fluctuating vibration amplitudes for generator casing vibrations (axial x, horizontal y, and vertical z directions). The time histories also showed four non-successive start-ups of Unit 2 prior to the eventual synchronization. Prior to start-up, the generator (drive-end casing) vibrations of Unit 2 were less than 2 mm/s (due to transmitted vibrations from the other two running units). Upon synchronization, horizontal casing vibration levels (y direction) of the Unit 2 generator increased to more than 10 mm/s and fluctuated between 8 mm/s to 15 mm/s, thereafter stabilizing at 11 mm/s. The time fluctuating vibrations were evident (and perhaps visually more obvious) in the time history plots for the axial (x) and vertical (y) directions. The vibration fluctuations spanned over 10 minutes.

Vibration time waveforms for measurements on the already op-

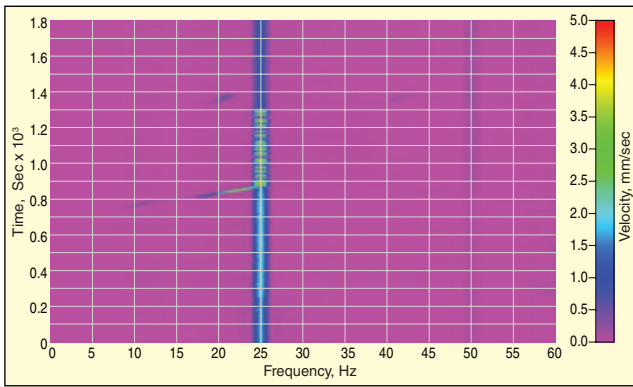


Figure 8. Spectral map of Unit 2 generator 1x filtered vibrations (vertical) during start-up process to loading.

erating Unit 3 (measured at the same time and displayed over the same time segments) are given in Figure 7. Prior to start-up of the stationary Unit 2, generator (drive end casing) vibrations of Unit 3 were below 10 mm/s. Upon synchronization of Unit 2, vibration levels on the Unit 3 generator increased up to 20 mm/s and fluctuated between 8 mm/s to 20 mm/s. Vibration levels on Unit 3 thereafter stabilized to levels similar to pre-synchronization (as partial load was transferred to the newly started Unit 2).

This start up sequence and vibration spectral peaks were evident in the spectral plots (FFT cascade plots plotted against time). A spectral plot for Unit 2 prior to and during start-up, synchronization and thereafter with load dispatch is shown in Figure 8. Fluctuations in vibration levels after synchronization for a significant duration (~10 minutes) were visually evident from the plots. The units continued with acceptable operations thereafter under partial-load operating conditions (up to ~80% system capacity).

Past experiences during full load (almost 100% system load) showed that the elevated vibrations during synchronization did not drop back to pre-synchronization levels and remained high (exciter shaft displacements above 3 to 5 mils p-p) based on manual readings from the control room monitoring system. This subsequently resulted in the units tripping as a result of high generator exciter shaft vibrations. It could be reasonably assumed that under full-load conditions, vibration levels increased corresponding to higher electrical loads. At these elevated vibrations, shaft rubs at the generator bearing may also occur, thereby aggravating the situation. (During the investigation, vibration tests were not undertaken up to full load conditions to avoid unnecessary system trip that would adversely affect the entire offshore platform's production).

Since the vibration levels during steady-state operation (with load dispatch) were acceptable, except for instances where full-load dispatch resulted in the units not "surviving" the synchronization related process, the cause of excessive vibration was shown to be related to likely faults in the synchronization system. Common faults in the synchronization are voltage out of phase, failures in wiring, settings of synchronization system, delays or faults in breaker closure, and flash-over in breaker's contacts (from inter-

nal or external pollution, low pressure dielectric, humidity and decomposition of breaker's insulation).


Discussion and Conclusions

Typical generator faults such as stator faults, unequal air gaps and mechanical faults inherently cause increased vibration levels. Vibration signatures of 1x RPM, 2x RPM and 2x line frequency (and its harmonics) lend itself to relatively straightforward identification of the faults. However, there are possibilities of misdiagnosis of a generator fault and misalignment as the 2x RPM and 2x line frequency associated with a misalignment and generator electrical fault are the same. For electrical motors, there is differentiating evidence by means of a slip frequency between the 2x RPM and 2x line frequency that differentiates a mechanical misalignment with an electrical fault. For synchronous generators, correlation of vibration levels against electrical power generation and load removal would be necessary, which could later readily confirm whether the vibration problem is electrically induced. This was demonstrated from the Case 1 study here.

However, there are other problems that could lead to excessive vibration during the synchronization process. But such failures and problems are not frequently reported in the literature. This article reports on time-varying vibration fluctuations predominantly at synchronous 1x RPM frequency and resulting from the synchronization of a third generator affecting two other generators already in operation (with load dispatch). Even though this was originally thought to be due to structure-borne vibration transmission on a common structural deck (in an offshore platform), the problem pointed to electrical faults in the synchronization process, with likely out of phase synchronization. The excessive transient vibration extremes during this synchronization process appeared to be load dependent and under full-load conditions had resulted in machine vibration alarm trips due to excessive vibrations.

While the literature on power system dynamics and stability tended to report on issues related to voltage instability arising from synchronization⁵ (which is indeed a major issue of concern to the electricity power grid), this article presents an operational perspective to the synchronization problem with respect to excessive vibrations induced in synchronous generators during synchronization. Such excessive vibrations can result in machine trips or potential restriction to electrical load generation.

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