TURBINE OVERSPEED TRIP PROTECTION

by

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ABSTRACT

This paper discusses the design, history, current standards and designs, and the relation between turbine overspeed and the time constant of rotors. Overspeeding of turbine rotors as it pertains to time lag of the overspeed devices and the amount of energy stored between the trip valve and the exhaust of the turbine is addressed. Also discussed are redundant "fail safe" designs that will give maximum protection and reliability.

INTRODUCTION

If the overspeed trip protection of a steam turbine fails to function at the design set speed, turbine buckets or a section of a wheel can break free of the rotor and, in a worst case scenario, penetrate the turbine casing. This can cause major damage to the turbine-driven equipment with a possibility of injuries and/or fatalities to individuals in the immediate area. There is also a very high probability that an oil fire will occur.

STANDARDS

Special-Purpose Steam Turbines for Petrochemical, Chemical, and Gas Industry Services, API Standard 612 (1995), Fourth Edition, June 1995, paragraph 2.6.1.2 states:

> "Rotors shall be capable of safe operation at momentary speeds up to 127% of the rated operating speed at normal operating temperature."

Paragraph 4.3.3.2.3 states:

> "Overspeed trip devices shall be checked and adjusted until values within 1% of the nominal trip setting are attained. Mechanical overspeed devices, when supplied, shall attain three consecutive nontrending trip values that meet this criterion."

General-Purpose Steam Turbines for Refinery Service, API Standard 611 (1988, Reaffirmed 1991), Third Edition, paragraph 2.6.1.1, states:

> "Rotors shall be capable of operating without damage at momentary speeds up to 110% of trip speed. This standard defines in paragraph 1.4.25 *Trip speed* (in revolutions per minute) is the speed at which the independent emergency overspeed device operates to shut down the turbine. The trip speed setting will vary with the class of governor see (3.4.2.7), Parameter Trip speed Class per NEMA SM 23 A is 115% of rated speed and for SM 23 B is 110% of rated speed."

At the maximum of 127 percent of rated speed, all the rotor stresses will be approximately 56 percent above the normal stresses with a corresponding reduction in the safety factors. API Standard 670 (2000) also addresses overspeed trip requirements.

International Standard (ISO/DIS) 10437 (1993) for petroleum and natural gas industries—special-purpose steam turbines is slightly different from the API Standard 612 (1995) referenced above. Paragraph 12.3.1.1 of 12.3 overspeed shutdown systems states:

> "A dedicated overspeed shutdown system shall be provided capable of independently shutting down the turbine. This system shall not be dependent on the governing system or any other system. The system shall prevent the turbine rotor speed from exceeding 127% of the rated speed on an instantaneous, complete loss of coupled inertia and load while opening at the rated condition. In the event of loss of load without loss of coupled inertia the systems shall prevent the speed from exceeding 120% of the rated speed unless otherwise specified by the driven equipment vendor. The turbine vendor shall have unit responsibility for the overspeed shutdown system."

Additionally, paragraph 12.3.1.2 states:

> "The overspeed system shall include but not limited to the following:
> a) electronic overspeed detection system (speed sensors and logic devices), API 670;
> b) electro-hydraulic solenoid valves;
> c) emergency trip valve(s)/combined trip throttle valve(s)."

OVERSPEED

If you have a car with a tachometer, you know what the red line value is. Every piece of rotating equipment has a red line value. The red line value is the maximum rpm (revolutions per minute) that the engine, turbine, or compressor should not be operated above. If the piece of rotating equipment is run above this limit, damage to the internal components will occur.

An overspeed trip shuts off the steam flow to the turbine, which causes the turbine rotor to decelerate.

ELECTRONIC TRIP SYSTEM

API recommends two speed sensors where:

- "A" or "B" trip signal is seen, then the turbine trips.
- "A" or "B" loss of signal or power, an alarm is given but the turbine remains running.
- "A" and "B" loss of signal or power, the turbine trips.

Figure 1 is the simplest system that can be used for a "special purpose steam turbine." This system is adequate if the loss of the turbine and the equipment driven by the turbine does not result in a significant upset and/or pose a safety hazard and/or damage the environment. If a turbine is determined to be in a critical service, a fault tolerant overspeed trip system should be utilized. In this case a minimum of three speed sensors is required where:

- Any combination of two trip signals will result in a turbine trip, i.e., "A" and "B," "B" and "C," or "A" and "C."
- The loss of power signal or power of any *one* of the speed sensors will result in an alarm.
- The loss of power or signal of any *two* of the speed sensors will result in a turbine trip.

(Note: This is for a de-energized to trip configuration as preferred by API.)

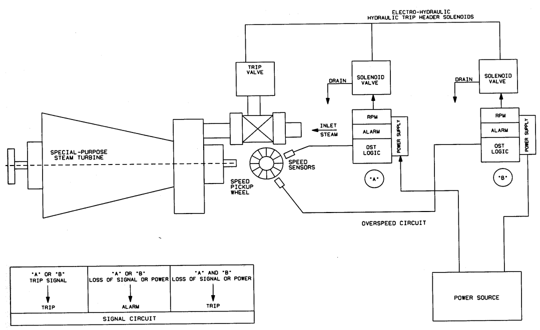

Figure 1. Overspeed Shutdown System.

Figure 2 is an example of the minimum electronic governor system for a general-purpose steam turbine.

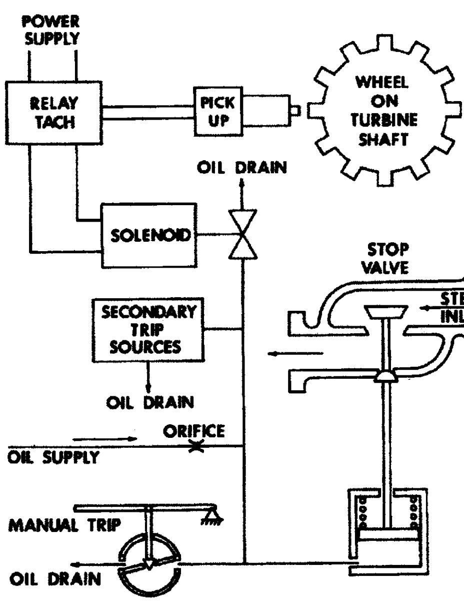

Figure 2. Example of Minimum Electronic Governor System for General-Purpose Steam Turbine.

Since the speed sensors are critical to the operation of the turbine, at least one spare speed sensor is normally installed. If an electronic fault tolerant governor is used, then three additional speed sensors and one spare are installed. A separate speed sensor is installed for the vibration monitoring system. All the speed sensors are reading one multitooth "speed pickup wheel" that is being held in position by a nonferrous mounting bracket (Figures 3 and 4). In addition to the speed sensors, two radial vibration probes, two thrust (axial position probes), thrust bearing temperature indicators, and radial bearing temperature indicators are normally installed. As is readily apparent to the most casual observer, the thrust end of the turbine is now taking on the appearance of the Starship Enterprise.

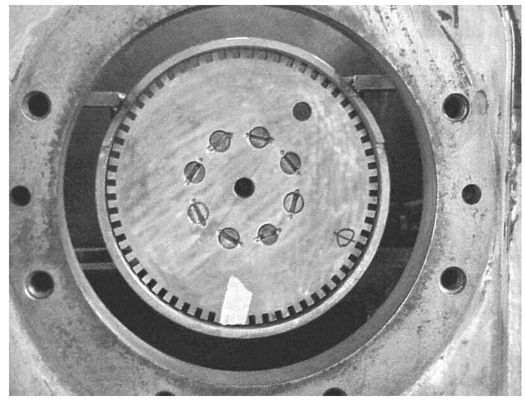

Figure 3. Speed Pickup and Sensor Mounting Bracket.

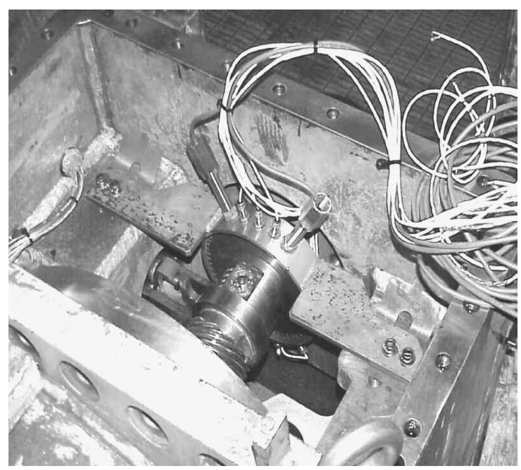

Figure 4. Top Half of Bracket with Sensors Installed.

MECHANICAL TRIP SYSTEM

Inside a mechanical overspeed trip mechanism there are four basic components. The internal components consist of two bushings, a plunger, and a spring as shown in Figures 5, 6, 7, 8, and 9.

One of the bushings is screwed completely into the overspeed trip body at a set depth. This controls the position when the turbine is not rotating. Then a bushing is installed over the plunger and spring, and then tightened down. The spring pushes against the plunger "stopper disk" and the adjustable bushing where the plunger extrudes from the body (Figure 5). Now the spring is in compression holding the plunger inside the mechanism body. The overspeed trip is then attached, typically bolted, to the outboard end of the rotor.

As the speed of the rotor increases, centrifugal force pulls the plunger to the outside, against the spring. As the rotor speed increases, the force from the plunger increases on the spring. Once

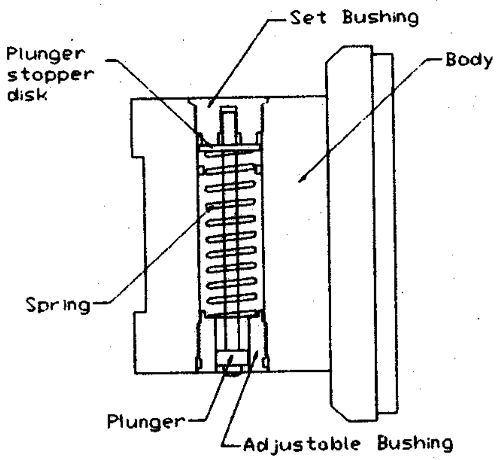

Figure 5. Mechanical Overspeed Trip Mechanism (Side View).

Figure 6. Mechanical Overspeed Mechanism Installed in Turbine Rotor.

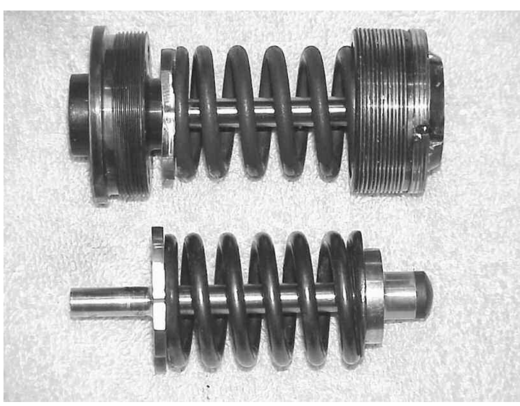

Figure 7. Mechanical Overspeed Mechanism.

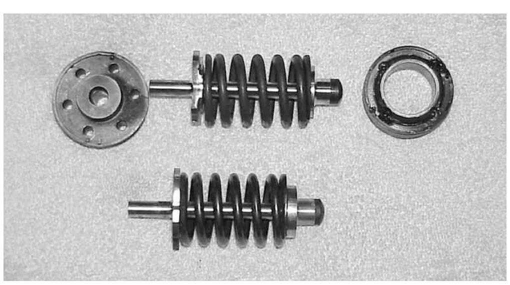

Figure 8. Mechanical Overspeed Mechanism Disassembled.

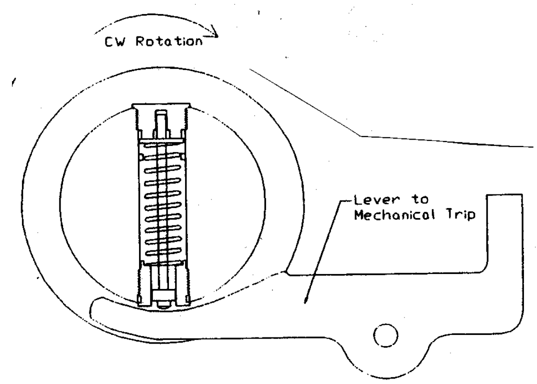

Figure 9. Mechanical Overspeed Trip Mechanism (End View).

the centrifugal force increases from the speed, rpm, the plunger overcomes the spring force causing the plunger to protrude outward.

A stationary lever, set with a relatively tight clearance, is positioned such that when the plunger moves out, the lever is struck. The lever is integral with the emergency mechanical trip device. When the mechanical trip is actuated, the hydraulic oil is dumped to the drain, which results in the immediate closing of the valve rack and trip valve.

The overspeed trip device is critical to the safety of the turbine. Without the overspeed protection, the turbine would run to destruction when the load (compressor, pump, or generator) was lost.

How fast the turbine accelerates determines how fast the overspeed trip system must respond (refer to Figure 10). If the turbine valves change their position instantaneously, this measurement of time is now as the time constant, T_C. The speed is a first order function of torque, and then the mathematical equation is:

$$n = 1 - \varepsilon^{-t/T_C} \tag{1}$$

where:

n = Per unit change, speed
ε = 2.71828
t = Time, seconds
T_C = Time constant, seconds

From Equation (1), when $t = T_C$, then $n = 1 - 1/\varepsilon$ or $n = 0.63$.

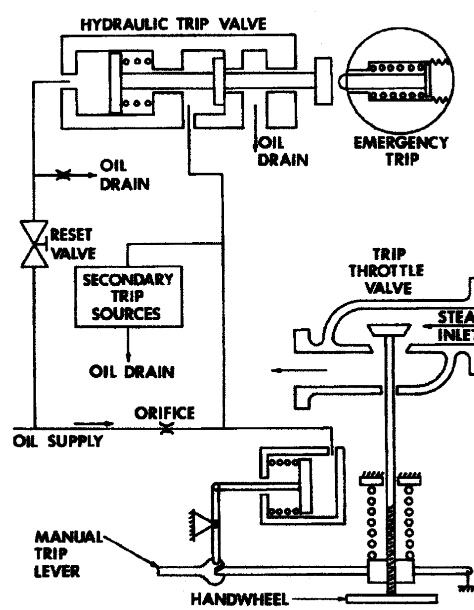

Figure 10. Overspeed Trip System.

Then, the rotor time constant gives the length of time that it takes the rotor to reach 63 percent of its total speed change due to an instantaneous change in the turbine valve position.

The rate of change at the instant the inlet valve's position changes are found by differentiating Equation (1) and setting the time to zero. The result is:

$$dn/dt = 1/T_C \tag{2}$$

From Equation (2), $d_n = 1.0$ when $d_t = T_C$, which leads to a second definition of the rotor time constant. The rotor time constant gives the length of time it would take the rotor to reach 100 percent of its total speed change due to an instantaneous change in turbine valve position if it continued to change speed at its initial rate.

Making the instantaneous valve opening correspond to the full load change can make the above definition clearer. Thus, the definition is changed to: the rotor time constant gives the length of time it would take the rotor to reach twice the speed due to a 100 percent instantaneous drop in turbine load, provided the rotor continued to change speed at its initial rate.

This definition is used to generally determine what would happen in a very short period of time between the loss of the load and the activation of the emergency trip device. It is assumed that the steam flow has not been changed and that all relationships are linear. Then for an instantaneous change in load and for very small values of time:

$$\Delta n = L\left(t / T_C\right) \quad or \quad t = \left(\Delta n / L\right)T_C \tag{3}$$

where:
t = Time, seconds
n = Speed change in time "t," percent
T_C = Rotor time constant, seconds
L = Instantaneous load change, percent

From Equation (3) it is seen that the rotor $T_C/10$ seconds to change speed 10 percent if there is an instantaneous 100 percent change in the load. This is a significant speed change in a short period of time. Thus, extremely fast speed controls and emergency overspeed tripping systems are required to limit the speed rise to a reasonable value when an instantaneous loss of load occurs.

ROTOR TIME CONSTANTS

The fundamental measure of rotor response is the rotor time constant. From the equation for horsepower, the rotor time constant can be calculated by substituting the speed and time for acceleration. The rotor time constant is:

$$T_C = 0.619\left(\left(N / 1000\right)^2\right)\left(\left(WR^2\right) / HP\right) \tag{4}$$

where:
T_C = Rotor time constant, seconds
N = Rated speed, rpm
WR^2 = Rotor inertia, lbs-ft^2
HP = Rated horsepower

The only factor in Equation (4) that depends on the rotor design of the turbine is the rotor inertia. It, the rotor inertia, cannot be calculated until the design of the turbine is complete. For mechanical drive turbines the rotor inertia varies considerably, but typically has an inverse relationship with the speed. The turbine rotor time constant, T_C, normally lies within a range of two seconds to eight seconds. There are rotors with a rotor response as quick as 0.5 seconds and some as long as 10 seconds.

The speed of the steam inlet valve(s), trip valve(s), solenoid valve(s), electronic and/or hydraulic controls or relays, and the rate of change of the load are measured relative to the rotor response time. The understanding of the total system response is critical. Any change that requires more than 1/10 of the rotor response time constant should be considered too slow. It is apparent that the slower the rotor response time and the load change coupled with a fast steam control(s) system is very desirable.

LOSS OF LOAD

Loss of the load, prior to this, has been considered instantaneous. This means that the loss of the load took zero time. The maximum speed change of the turbine rotor is the result of an instantaneous loss of load. Thus, what is the difference between the turbine rotor speed response to an instantaneous loss of load as opposed to a sudden loss of load?

In 0.05 seconds or less, a couple of cycles, a turbine driving an electrical generator can lose full load. This is the type of situation where the loss of load must be considered instantaneous. The protection system(s) should then be designed accordingly. One advantage to this situation is that the loss of load can occur without the failure of the coupling(s) between the turbine and the generator and, in some installations, the gearbox. In this situation the time constant would include the turbine rotor and the generator rotor, WR^2. The increase in the overall system rotor time constant will reduce the probability of an overspeed.

Mechanical drive steam turbines, turbines that drive compressor(s), pumps, fans, blowers, etc., are entirely different. There are four ways a *sudden* loss of load can occur.

- A throttling of the suction, but in this case there would only be a partial load reduction. Surging a compressor or breaking suction of a pump may still require as much as 30 percent of the full load. The time required to throttle the inlet would require a minimum of one second to two seconds. This would only be a problem with very slow 10 second turbines.
- A coupling failure, which is rare in this day and age. There are no data on the time; however, in analysis of a few coupling failures, the complete failure would take one second to two seconds.
- A loss of load due to a process upset takes seconds to be accomplished. In most cases of a process upset, the loss of load is only partial. This again gives the system time to respond.
- A catastrophic failure of the discharge piping in close proximity of the driven equipment.

It is apparent, from the discussion above, that a required response time of the overspeed trip protection system of one second is sufficient as a result of a 100 percent sudden loss of load. Again, the response time constant must include the WR2 for all the rotors of that drive train.

TIME LAG AND STORED ENERGY

During an overspeed situation, there are two reasons the speed of the rotor will increase above the 110 percent of maximum continuous speed or high-speed stop. The first is the time lag in the mechanism that closes the steam inlet valves and/or the stop valve. And the second is the steam energy stored in the turbine, nozzle box, valve chest, and piping located between the stop valve and the steam chest of the turbine.

By equating the stored energy of the steam to the change in the kinetic energy of the turbine rotor, the change in the rotor speed can be determined mathematically. Equation (5) shows the maximum speed the turbine rotor can reach above the trip speed due to the stored energy. Equation (5) is based on the assumption that the turbine has an efficiency of 60 percent at the design rated load and steam conditions as the stored energy is used.

$$\left(N_f / N_t\right)^2 = 1 + \left(2.72\left(BTU\right)\right) / \left(WR^2\left(N_t / 1000\right)^2\right) \tag{5}$$

where:
N_f = Maximum speed
N_t = Trip speed, rpm
BTU = Total stored energy
WR^2 = Rotor inertia, lbs-ft

The amount of stored energy in the steam chest, nozzle box, and the turbine case downstream of the nozzle box is extremely difficult to quantify. In an effort to make things a bit easier, Equation (5) can be reduced to address the stored energy in the piping between the trip throttle valve and the steam chest. Thus, the feet of inlet piping (*P*) between the trip throttle valve and steam chest required to reach an overspeed can be calculated.

$$P = 0.095 T_C V \tag{6}$$

where:
P = Length of inlet piping between trip throttle valve and turbine steam chest, feet
T_C = Turbine rotor time constant, seconds
V = Steam velocity in inlet piping, ft/sec

With a steam inlet velocity of 150 ft/sec and a 1/2 second time constant, the length of pipe required to overspeed the turbine from a trip speed of 110 percent of the rated speed to a maximum speed of 115 percent of the rated speed would be 7.125 feet of equivalent pipe.

If the actual overspeed trip of the rotor exceeds the API margin of error, then action should be taken to address the time lag and/or the stored energy. The time lag due to slow response of the system can be remedied by the replacement of slow valves with faster valves and/or increasing the hydraulic pressure in the control oil system. True stored energy can be addressed by lowering the trip speed set point of the overspeed protection mechanical or electrical. This, however, can present a problem. If the true trip speed is above the desired trip speed due to very rapid acceleration of the turbine rotor but the actual trip speed is within the design parameters at a slow acceleration from the governor high speed stop, then early trips may be experienced. Although the machine is adequately protected, the early trip may become a problem to the reliability of the process. This situation can be seen if the WR2 of the equipment train is very low. An example of this would be where a turbine is driving a single compressor, the turbine has 15 percent excess power, and the molecular weight of the gas being compressed is low. A simple electronic system is shown in Figure 11, and a dual electronic system is shown in Figure 12.

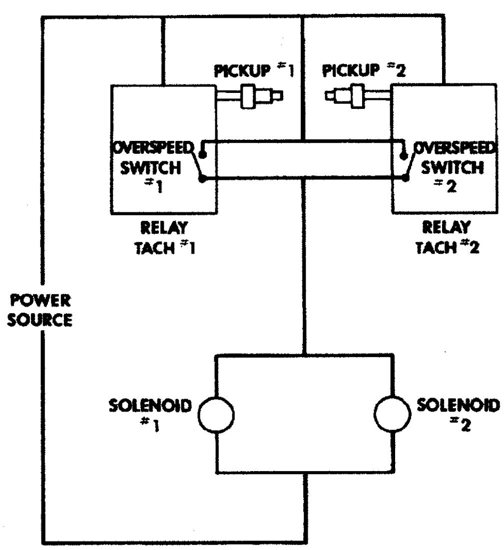

Figure 11. Simple Electronic System.

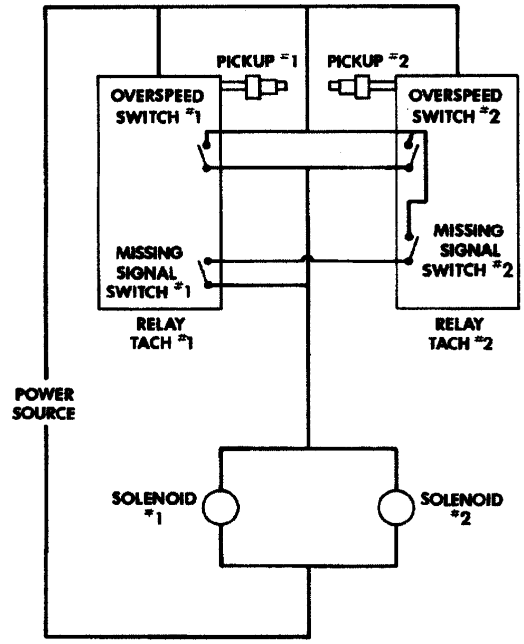

Figure 12. Dual Electronic System.

TESTING

A steam turbine solo is the testing of the turbine with the turbine uncoupled from the machine train. The soloing of the turbine is required to:

- Determine the actual critical speed
- Define minimum governor set point (low speed stop)
- Determine maximum governor set point (high speed stop)
- Test the emergency trip systems

Included in the testing of the emergency test systems is the testing of the overspeed trip set point(s). As long as the governor functions properly, the operation of running up to the overspeed set point(s) is a conscious decision of the individuals involved in the testing. The highest exposure to a potentially dangerous situation for the individuals and equipment involved is at this point in time.

Every company that the author has been associated with, directly or as a nonpaid consultant, has had a written overspeed trip test procedure for turbines. In most cases, the procedure is followed to the letter when testing the large and/or critical turbines. Typically these procedures define responsibilities, frequency, exceptions, maintenance activities, safety requirements, and procedures. In the past few years, in addition to the written procedure, a graphical outline of the procedure for each individual steam turbine was developed and provided to all the individuals involved in the overspeed trip testing (Figure 13). This has minimized any confusion or misunderstanding.

During the research for this paper, it was found that the run to an overspeed failure of a large/critical steam turbine was rare. It is believed that this is a result of the amount of attention to the detailed procedures is at its highest. These situations are typically on new installations or after an overhaul where sensitivity is at its highest. With the use of electronic overspeed trip protection and the upfront testing of the emergency trip system, the overspeed testing as it relates to speed should be a nonevent. Problems with high vibration due to rotor bows and rubs, unbalance, damaged bearings, and improperly installed bearings, etc., are outside the scope of this paper.

The preliminary steps to validate the safety protection systems function prior to the physical testing of the turbine overspeed are:

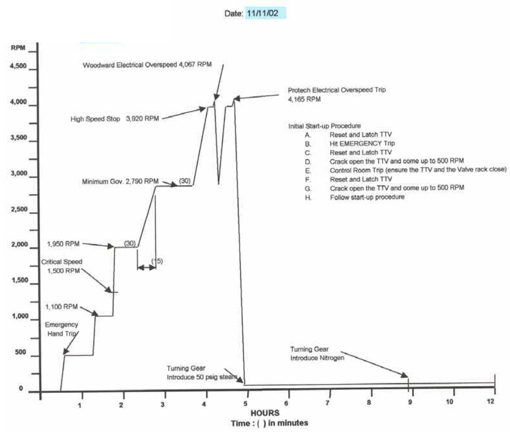

Figure 13. Graphical Outline of a Steam Turbine.

- Signal generator is used to test the overspeed set points, if an electronic governor is used and/or an independent electronic overspeed protection system is used.
- Oil trips.
- Emergency trips, mechanical, electronic, and manual, on the turbine platform and in the control room.
- When possible the mechanical overspeed plunger assembly should be removed from the turbine rotor and tested in a spin pit if the mechanical trip is to provide primary or secondary overspeed protection.

After all the initial checks are made, the turbine rotor can be brought up to a slow roll state, typically between 100 rpm and 1000 rpm. The slow roll speed varies based on the design of the turbine. Once the turbine is up to the temperature desired, the oil trips should be tested again in addition to all the emergency trips before ramping up the turbine speed. Functionality of the trip devices should also be checked at this time.

The next step is to validate or set the minimum governor speed and the maximum (high speed stop) governor speed. This step can be quite difficult when the governor is a mechanical/hydraulic system.

It is now time to test the overspeed trip protection system in earnest. The electronic protection systems are the easiest to validate. The set points should have already been verified. Thus, the testing is, or is hoped to be, a formality.

The hybrid overspeed trip system consisting of mechanical/electronic devices is the next easiest. The electronic overspeed trip set point must be set *below* the mechanical overspeed trip assembly. If the electronic overspeed trip point is set above the mechanical set point, then the only way to test the set point is with a signal generator, because it should be impossible to run past the mechanical set point. This is true if the mechanical set point is set properly and the assembly functions as designed.

The mechanical overspeed trip assembly is not very high tech. These systems use a bushing, adjustment nut, plunger, and spring arrangement. As the spring is compressed, the force to overcome the spring force is increased as the force to overcome the spring force is reduced. The weight of the plunger, spring force, speed, and the distance from the plunger to the trip lever defines the trip speed. Since the desired trip speed, the weight of the plunger, and the distance the plunger must travel to strike the trip lever are fixed, the only adjustment that can be made is the spring force. Adding or removing shims, or repositioning the spring compression adjustment nut, changes the trip speed. The only way to change the trip speed is to shutdown the turbine to make the mechanical adjustments. Multiple runups are not unusual. This is time consuming and introduces a potential for human or mechanical error. The author has experienced many problems over the years with the setting of mechanical governors, to list a few:

- Trip plunger improperly machined, a phonograph finish on the bore of the plunger guide bushing
- The end of the plunger was flared out preventing the trip plunger from moving. This was the result of a millwright physically pushing on the end of the plunger with a center punch of drift.
- The plunger and guide bushing had a buildup of varnish.
- The installed spring was too strong.
- The installed spring was too weak from either an old spring that had lost some of its force or a spring with too low a spring constant.
- The millwright turned the adjustment nut in the wrong direction.

If everything is perfect, then a mechanical/hydraulic system will protect the turbine from self-destruction when an instantaneous or a sudden loss of load is experienced.

A comparison of a mechanical overspeed trip system versus an electronic trip system is shown in Table 1.

Table 1. Comparison of Mechanical Overspeed Trip System Versus Electronic Overspeed Trip System.

Mechanical Overspeed Trip System	Electronic Overspeed Trip System
General trip speed range, typically ± 50 rpm	Precise trip speed, digital set point
Trip speed **will** change over time	Trip speed **will not** change over time
Does not interface with anything	Provides DCS interface
Does not provide any indications of trip	Provides first out trip indication
Must have mechanical trip lever interface	No physical contact with shaft or mechanical trip lever is required
Oil varnish buildup will keep the mechanical trip plunger from functioning	Oil varnish does not affect the trip function
Not fault tolerant	Fault tolerant
Cannot be tested except when uncoupled from the driven equipment, which requires a shutdown	System can be tested periodically with a signal generator with minimal or no risk to the operation of the turbine
Must be initially set in a spin test pit	Set by signal generator
Requires multiple runs of the turbine to adjust the trip set point in the field	**Does not require ANY extra runs of the turbine in the field**

INCIDENTS

Incident 1

A 22 Megawatt, 3600 rpm unit oversped to at least 5400 rpm as a result of the disk and bolt, from an upstream extraction nonreturn valve, became loose and moved into a position that resulted in the nonreturn valve sticking open (Figures 14, 15, and 16).

Figure 14. Generator.

Figure 15. LP Turbine End to Generator.

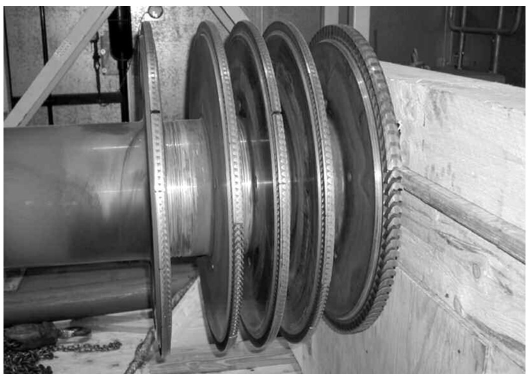

Figure 16. Turbine Rotor (Incident 1).

Incident 2

An incident showing a turbine driving a generator with an instantaneous loss of load is shown in Figures 17, 18, 19, and 20.

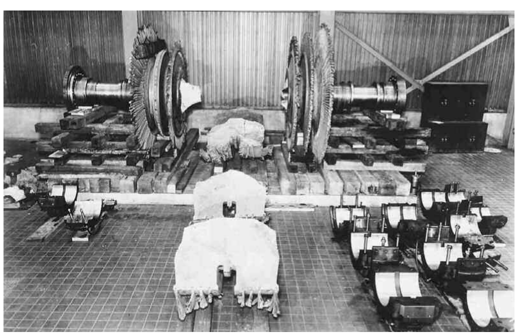

Figure 17. Turbine Rotor (Incident 2).

Incident 3

On 02/24/01, a condensing steam turbine driving a blower in a steel plant went past the overspeed set point. One individual was killed and another individual was injured. The turbine developed about 8500 hp and was designed to run at 4100 rpm with the overspeed trip set at 4500 rpm. The first overspeed trip test was successful. On the retest, the highest logged speed was 4988 rpm, but eyewitness accounts say the reed tachometer showed 5300 rpm.

Incident 4

A catastrophic failure of a 300 hp, 3600 rpm, boiler feed water pump drive turbine occurred on 05/30/00. The turbine disintegrated due to overspeed following a coupling failure and a

Figure 18. Turbine Generator Bay (A, Incident 2).

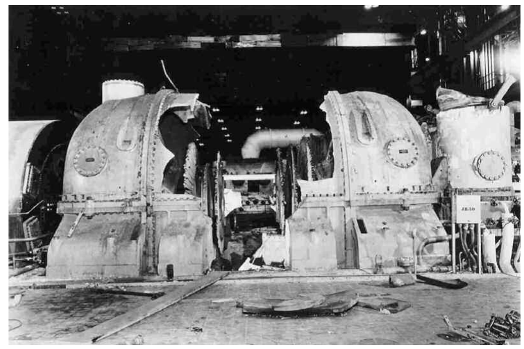

Figure 19. Turbine Generator Bay (B, Incident 2).

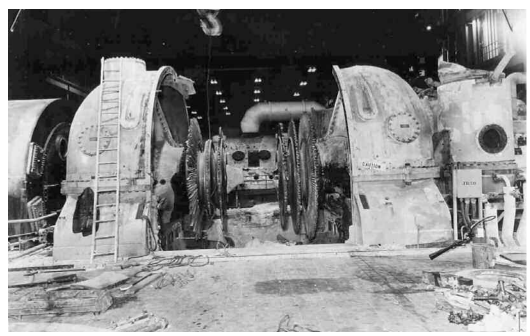

Figure 20. Turbine Generator Bay (C, Incident 2).

governor oil pump shaft failure. The overspeed trip valve closed, but not fast enough to prevent a very severe overspeed. No one was injured during this event.

Incident 5

On 01/01/98, a condensing steam turbine driving a water pump in the United Kingdom failed during an overspeed trip test. The turbine was rated for 600 hp at 4643 rpm, with a steam inlet pressure of 40 psig. Two reed tachometers were used to measure the turbine speed, and the first trip test was successfully completed at 5400 rpm. On the second test, the operator reported the reed tachometer reading was 4900 rpm and heard the trip mechanism start to "clatter" as the turbine disintegrated. The operator at the trip throttle valve died on the way to the hospital from the injuries sustained; two other employees received severe injuries requiring multiple surgeries. Debris from the turbine was scattered over a wide radius, and adjacent equipment was damaged. Calculations show that the blades should not have been overstressed and thrown below 8000 rpm. The incident investigation concluded that there may have been a misinterpretation of the turbine speed on the reed tachometer, the overspeed trip mechanism malfunctioned, and excessive steam flow was available for the test.

Incident 6

An operator, about 15 years ago, was putting a steam turbine driven refrigeration compressor online, and he was reading the speed with a reed tachometer setting on the auxiliary oil pump turbine, which was normally off. The lube oil pump was running because the shaft driven governor oil pump had failed. The lube oil turbine ran at 3600 rpm and the main turbine was designed to run at 3800 rpm. The operator kept giving the main turbine more steam because he believed the turbine would not speed up past 3600 rpm. Calculations showed that the compressor impellers actually flew apart at 5400 rpm. Pieces of the compressor were thrown throughout the building barely missing the operator. The overspeed trip valve should have prevented the turbine from overspeeding, but the valve was stuck open from steam deposits.

INSURANCE DATABASE

A commercial insurance company (Clark, 2002) has been maintaining a database concerning overspeed failures. The database captures, when possible, the:

- Year of the incident
- Size of the turbine
- Driven object
- Why the governor failed to control the speed
- Why the overspeed trip failed
- Other factors/information

This is an excellent database; however, it is not totally accurate. The database input information is based on information supplied by companies that are insured by this company and individual input. If the overspeed incident does not result in major damage and/or personnel injuries, the incident may not be reported. (Refer to APPENDIX A for a sample incident table.)

CONCLUSION

A safe, reliable, fast-acting overspeed trip protection system is required. The system will be tested initially while the turbine is down and then again, at speed, with the turbine uncoupled from its load. When the solo testing is performed, the level of risk to the personnel and equipment is at its greatest. The designer must take into consideration the instantaneous loss of load while the turbine is in operation. However, the entire protection system—electrical, mechanical, and hydraulic components—must perform flawlessly. Human errors can and must be minimized through training and practice, but they can never be eliminated. Every turbine must be treated as the most critical and dangerous piece of equipment in the plant.

APPENDIX A

Table A-1. Steam Turbine Overspeed Incidents—Contributing Factors (05/02/97)—#1 through #20.

STEAM TURBINE OVERSPEED INCIDENTS - CONTRIBUTING FACTORS (05/02/97)

INCIDENT NUMBER	YEAR	SIZE	DRIVEN OBJECT	WHY GOVERNOR FAILED TO CONTROL SPEED	WHY OVERSPEED TRIP FAILED	OTHER FACTORS / INFORMATION
1		>5000 hp			T/T Valve Stuck	Occurred during normal operation; exact details not known.
2		<5000 hp			T/T Valve Stuck	Occurred during normal operation; exact details not known.
3		<5000 hp			T/T Valve Not Operational	Occurred during uncoupled overspeed trip test. One fatality. Turbine destroyed.
4	1987	>5000 hp	Cent. Compressor	Retrofitted electronic governor improperly configured. System in manual; system ignored overspeed signal.	T/T Valve assembled improperly causing it to not close fast enough to prevent overspeed. Valve was closed after accident; probably closed due to severe vibration during accident.	Coupling installed incorrectly during turnaround. During process upset, coupling spun on shaft which unloaded turbine. Turbine oversped to complete destruction; case could not be repaired.
5	1995	>5000 hp	Cent. Compressor		T/T Valve stuck; improperly adjusted	Coupling broke causing turbine to unload. Coupling improperly installed. Rotor could not be repaired; case was repaired.
6	1987	>5000 hp	Generator	Probably stuck due to steam deposits.	Probably stuck due to steam deposits.	Details not available, but steam quality was a primary factor. Turbine and generator oversped to complete destruction.
7	1987	>5000 hp				Details not available.
8	1986	>5000 hp	Compressor	Valve stuck due to boiler carryover deposits.	Valve stuck due to boiler carryover deposits.	Extreme boiler carryover.
9	1960s	<5000 hp	Recip. Cmpr.	Direct mechanical type governor; reason governor did not control speed not known.	Either stuck open due to steam deposits or failed to close fast enough. Butterfly type valve.	Gearbox between turbine and compressor failed which unloaded turbine. Turbine centrifugally exploded; totally destroyed with damage to surrounding building and objects.
10	1976	<5000 hp	Fan	Governor was oil pressure to close type. Lost oil, so governor went wide open.	Stuck due to steam deposits.	Nipple on gearbox oil drain line broke due to fatigue. Without oil, gearbox failed which unloaded turbine. Gearbox oil also supplied governor system. Turbine centrifugally exploded; large sections of case thrown some distance. Total loss.
11	1995	<5000 hp	Fan	Governor out of service during uncoupled trip test.	Probably, trip setpoint set too high.	Turbine oversped during uncoupled overspeed trip test.
12	1988	<5000 hp	Fan			Probably steam quality and maintenance related.
13	1970s or 1980s	<5000 hp	BFW Pump			Pump was in service - may have rotated backwards after turbine tripped due to stuck check valve. Turbine disintegrated.
14	1980s	>5000 hp	Cent. Compressor	Unknown	Valve stuck, probably steam deposits.	Oversped during uncoupled trip test. Stopped turbine by manually tripping governor valve; should have closed automatically, but did not.
15	1985	<5000 hp	Cent. Pump	Steam was off to turbine; turbine driven by pump.	Steam was off to turbine, turbine was driven by pump.	Due to pump check valve sticking open, turbine oversped in reverse rotation. Turbine damaged, but all components stayed in the case.
16	1985	<5000 hp	Cent. Pump	Steam was off to turbine, driven by pump.	Steam was off to turbine, turbine was driven by pump.	Due to check valve sticking open, turbine oversped in reverse rotation. Same turbine as above. This time, turbine centrifugally exploded; turbine destroyed.
17	1996	>5000 hp	Generator	Design of governor system was such that governor did not close when overspeed trip signal was received or when emergency stop button was actuated. During incident, governor sensed falling speed and opened governor valve 100%	Trip valve hung open; probably steam deposits. Prior to the accident, the governor valve had been sticking due to steam deposits, and a spare valve was scheduled to be installed during next outage.	Operator was shutting down turbine generator. He decreased load on generator, then hit emergency trip button which disconnected load. Trip valve did not close. Governor valve was wide open. Turbine oversped. Exciter centrifugally exploded.
18		>5000 hp	Cent. Cmpr.		Hydraulic relay in speed sensing / trip system stuck preventing closing of trip valve.	
19		>5000 hp	Cent. Cmpr.		Hydraulic relay in speed sensing / trip system stuck preventing closing of trip valve.	Same plant as above accident; stuck relay was not diagnosed in first incident, so it caused another accident.
20		>5000 hp				Insulation sagged enough to interfere with the movement of the weighted arm on an extraction line check valve. When turbine tripped and check valve did not close, turbine oversped by backflowing extraction steam.

Table A-2. Steam Turbine Overspeed Incidents—Contributing Factors (05/02/97)—#21 through #34.

STEAM TURBINE OVERSPEED INCIDENTS - CONTRIBUTING FACTORS (05/02/97)

INCIDENT NUMBER	YEAR	SIZE	DRIVEN OBJECT	WHY GOVERNOR FAILED TO CONTROL SPEED	WHY OVERSPEED TRIP FAILED	OTHER FACTORS / INFORMATION
21		<5000 hp		Governor out of service during uncoupled trip test.	OEM trip throttle valve linkage was so "flimsy" it could be relatively easily distorted enough that valve would not trip. After accident, replaced T/T valve on five machines with similar linkage.	Turbine oversped to destruction.
23	1950 to 1996					Turbine oversped during uncoupled or low load test of the overspeed trip system. All of the following are from Ed Nelson's paper.
24		>5000 hp	Generator	Governor and/or extraction valve stuck due to poor steam quality.	Trip valve stem stuck due to poor steam quality. During accident investigation, trip valve stem could not be moved with a 25 ton jack plus oil and sledge hammer.	Also human error. Operator could not decrease generator load below 10% due to sticking governor valve, but he disconnected the load anyway. Should have shutdown machine by closing steam block valve.
25		>5000 hp	Generator			Extraction check valve failed to close because a sprinkler pipe had been installed that interfered with the check valve counterweight arm. Unit tripped during thunderstorm; then oversped with extraction steam. Generator exploded; oil fire ensued.
26		>5000 hp	Generator	Stuck open; reason unknown.	Stuck open; reason unknown.	Face of coupling flange not machined true; bending moment caused solid coupling to break. Turbine oversped. Because of extreme destruction, cause of valves sticking open could not be determined.
27		>5000 hp	Cent. Cmpr.	Found closed after wreck.	Stuck open; probably poor steam quality.	Coupling bolts failed sequentially due to misalignment. Increasing vibration ignored by operators. Coupling finally thrown completely. Turbine parts demolished exhaust casing.
28		>5000 hp	Cent. Cmpr.			Coupling hub installed with insufficient shrink fit; also sharp corners on bore. Fretting/rubbing caused hub to dig into shaft. Shaft failed by fatigue. Unloaded turbine oversped.
29		<5000 hp	Cent. Pump	Direct mechanical type governor failed to respond fast enough when trip valve was suddenly opened.	After turbine repeatedly tripped on overspeed, operators secured overspeed trip in open position with bailing wire.	Turbine was tripping on overspeed because of restricted pump suction. When overspeed trip was defeated with bailing wire, turbine centrifugally exploded. Case was destroyed. One fatality and one serious injury.
30		>5000 hp	Generator	During startup, first valve in rack system "popped" open. Linkage system included a spring which let valve open more than a more rigid system would allow. Turbine oversped before governor could gain control.	Unknown	Generator centrifugally exploded during overspeed. Design of control system required that turbine be started up on governor valve rather than with a block valve. Due to large pressure differential, it is common for first rack valve to "pop" open.
31		>5000 hp	Cent. Cmpr.	Shaft broke causing loss of governor/speed input.	Shaft broke causing loss of speed indication.	When shaft broke, governor sensed low speed and went wide open. Turbine oversped, but components stayed in case. Speed limited by compressor load. Design errors included wrong shaft material and wrong bearing type.
32		>5000 hp	Paper mill line shaft	Valve stuck open; probably due to steam deposits.	Trip valve stem was bent. Also, switch in trip circuit was wired "normally open" instead of "normally closed" per OEM's drawing error.	Operators had been able to start turbine for years in spite of incorrectly wired switch. However, when governor valve stuck open, turbine oversped when trip valve was reset during startup. Line shafts tore loose from bearings and destroyed a large area.
33		>5000 hp		Out of service for uncoupled test.	Trip inoperative; was being set at manufacturer's test stand.	Speed was monitored with strobe light. Operator did not notice shaft was spinning at twice the strobe flashing speed. One fatality. Turbine destroyed.
34	1997	<5000 hp	Cent. Pump		Mechanical overspeed trip system had been improperly assembled / adjusted during last overhaul. Trip bolt functioned, but rest of system not actuated.	Coupling failed which initiated turbine overspeed. Reason for coupling failure not known.

Table A-3. Steam Turbine Overspeed Incidents—Contributing Factors (05/02/97)—#35 through #53.

STEAM TURBINE OVERSPEED INCIDENTS - CONTRIBUTING FACTORS (05/02/97)

35	1990s	>5000 hp	Cent. Pump			Pump lost suction which unloaded turbine. Turbine oversped to destruction; not repairable. Another source said this was a fatality accident.
36		<5000 hp				During uncoupled test, small turbine oversped.
37	1990s					During uncoupled test, turbine oversped to destruction. One fatality.
38	1984	<5000 hp	Cent. Pump	Governor valve gagged partly open so machine could be slow rolled in normal service.	Combined governor/trip valve (butterfly type).	Turbine oversped during uncoupled overspeed trip test. Vibrating reed tachometer apparently was misread during test. Turbine and gear completely destroyed.
39	1985	<5000 hp	Cent. Pump	Governor system response was too slow to control speed when pump lost suction.	Combined governor/trip valve (butterfly type).	Pump lost suction which unloaded turbine. Turbine oversped to destruction.
40	1988	<5000 hp	Cent. Compr.	Governor valve stuck due to steam deposits.	Trip valve stuck due to steam deposits.	Compressor surged heavily causing loss of load. Turbine overspeed with damage. Cast aluminum impellers in compressor also destroyed.
41	1993	<5000 hp	Cent. Pump	Unknown - possibly response too slow.	Trip valve stuck due to steam deposits.	Coupling gear teeth failed which caused loss of turbine load. Turbine oversped.
42	1984	<5000 hp	Cent. Cmpr.	In manual control for uncoupled overspeed trip test.	Electrical/electronic overspeed trip system failed due to a broken part. Mechanical overspeed trip system failed also; a critical adjustment was in specifications, but just barely.	During uncoupled test, turbine oversped to 120% of maximum design speed. Machine was not damaged.
43	1997	>5000 hp	Generator			11 MW unit was known to have oversped - top rpm est. 5100 while design was 3600. Damage discovered during 5 year scheduled overhaul. Retaining rings and some turbine components damaged.
44	1995	>5000 hp	Generator	Too slow	Too slow	A gear (which gear unknown, probably in mechanical governor drive) of the wrong material failed. Turbine oversped before trip system actuated. Generator damaged beyond repair and replaced with a used unit.
45		<5000 hp	Pump			Coupling Failure
46	1994	<5000 hp	Cent. Pump			Boiler feedwater pump cavitated due to process upset. Overspeed trip and governor did not work properly; reason unknown. No testing program for governor or overspeed trip prior to incident. Governor centrifugally exploded, but no injuries.
47	1995	<5000 hp	Cent. Pump			Steam turbine driving cooling tower water pump oversped to destruction.
48	1979	>5000 hp	Axial flow compressor			Steam turbine and axial flow compressor oversped to destruction. Details not known why governor and overspeed trip failed. Unit down months. Coupling failed catastrophically, but no injuries. Parts of case of compressor and steam turbine salvaged.
49	1997	<5000 hp	Cent. Pump	Governor was noted to always operate wide open following turbine rerate, but no corrective action was taken.	Pump cavitated, turbine oversped. Retainer that holds trip bolt in shaft failed ejecting trip bolt from shaft. Trip was then no longer operative.	Flyball type governor came apart during overspeed event but parts stayed inside the machine. Trip lever would not reset, so operator held it up manually. A "brace" was installed to hold up the turbine trip lever. Turbine oversped again, and operator noticed that the scatter shield on the end of the turbine was beginning to dent, so he shutdown turbine.
50	1995	<5000 hp	Cent. Pump			Pump in Sulfuric Alky unit was operated dry/cavitating. Turbine oversped to destruction.
51	1989	<5000 hp	Cent. Pump			Cooling tower water pump turbine oversped after coupling failed.
52	2001					Turbine overspeed trip was being tested. Had worked successfully twice. On third try, turbine overspeed. Speed was being controlled by control valve rather than block valve. One fatality and one injury.
53	2001	>5000 hp	Generator			R. West reported. No details.

Table A-4. Steam Turbine Overspeed Incidents—Contributing Factors (05/02/97)—#54 through #57.

STEAM TURBINE OVERSPEED INCIDENTS - CONTRIBUTING FACTORS (05/02/97)

54	2001	>5000 hp	Generator			Due to upset in mill, other generators were shutdown resulting in subject generator operation at maximum load. For some reason, load was lost. Broke bearing pedestals, threw pieces through room and into side of pressure vessel. Solid coupling bolts sheared. At least one injury; no fatalities. Turbine had been retrofitted with electronic governor, but this was not used for overspeed protection.
55	?	>5000 hp	Generator			In past, turbine generator oversped to the point retaining hardware failed in the generator.
56	?	>5000 hp	Governor			In past, turbine generator oversped to the point retaining hardware failed in the generator.
57	1999 ?	<5000 hp	Generator		Turbine oversped during overspeed trip testing. Operator accidentally opened steam valve too much while turbine was disconnected from generator.	

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