EPRI

General Electric Electrohydraulic Controls (EHC) Electronics Maintenance Guide

Technical Report

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R E P O R T   S U M M A R Y

General Electric Electrohydraulic Controls (EHC) Electronics Maintenance Guide

Steam turbine electrohydraulic control system maintenance problems have been a significant factor in plant power reductions, shutdowns, and lost generation. This guide provides recommendations to improve the reliability of the electronic circuits and components of General Electric EHC systems.

BACKGROUND Although considerable effort has been expended in improving EHC system reliability, failures resulting in lost generation and high maintenance costs still plague the industry.

OBJECTIVES

- To provide maintenance recommendations for system electronics
- To identify design changes and maintenance practices that have improved reliability on an individual basis

APPROACH Through the use of a comprehensive survey, design changes and maintenance practices that improved system performance were identified. Input was obtained from over 40 nuclear plants that responded to the survey. Failure reports were reviewed to establish trends and patterns in the types of system problems. This information formed the basis for the recommendations developed by the project team. The project team consisted of 18 utility engineers, one INPO representative, the task contractor, and the EPRI project manager.

RESULTS This guide provides information that can be used by utilities to improve EHC maintenance practices and procedures. The guidelines are geared toward providing system engineers and/or maintenance supervisors with the information and guidelines needed to improve site-specific maintenance procedures and processes. This guide contains:

- Descriptions of the electronic systems in EHC.
- Data on system and electronic component failure history for each type of GE-EHC. The history is evaluated to identify trends and document the causes, components, and subsystems involved in the events.
- Summaries of current maintenance practices used by the utilities.
- Guidelines on the maintenance and operation of the systems, which are based on the history of the system electronics and on current utility practices.

INTEREST CATEGORIES

Maintenance practices
Nuclear plant operations and maintenance
Electronic systems and equipment
Engineering and technical support

KEYWORDS

Control equipment
Electronics
Maintenance
Predictive maintenance
Preventive maintenance

EPRI PERSPECTIVE The turbine hydraulic control system continues to cause unplanned plant shutdowns due to component failures and inadequate control system performance. Obsolescence of the installed control system components has contributed to system problems. This guide will serve as a valuable source of information for plant personnel who are evaluating their control system to determine how to improve performance.

PROJECT

TR-108146

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ABSTRACT

Many nuclear power plants use General Electric turbines and the associated electrohydraulic controls (EHC). As the systems age, support for them becomes difficult because some of the devices used in the system are no longer available. This maintenance guide provides information that can be used by system engineers and / or maintenance supervisors to improve maintenance practices and procedures. Over time, these EHC units have accrued hundreds of years of operating experience. This report evaluates the operating experience based on events in various databases and on a survey of utility personnel. The event evaluation indicates that the frequency of problems on units with Mark I EHC systems appears to be increasing, while the frequency for Mark II EHC systems appears to be decreasing. The evaluation indicates that the problems experienced at the various sites cover a broad spectrum. There does not appear to be any specific device or class of device that are responsible for fleet-wide problems. Therefore, any maintenance program for EHC systems must be broad based and consider all portions and devices in some detail.

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INTRODUCTION

General Electric (GE) steam turbines and the associated electrohydraulic controls (EHC) have been widely used in nuclear power plants for more than 25 years. Over time, various problems in the EHC systems have occurred and have been addressed. In addition, the support for the systems is becoming difficult because devices used in them are no longer available. This guide describes the EHC systems, analyzes the database of events attributed to these systems, examines current utility practices with regard to them, and provides conclusions and maintenance recommendations based on the evaluations.

There are two basic models of GE-EHC systems, known as Mark I and Mark II, in nuclear power plants. Both of these models will be addressed in the guidelines. There are considerable differences between their implementation in boiling water reactors (BWRs) and pressurized water reactors (PWRs). The types to be covered in this report are:

1. BWR Mark I
2. PWR Mark I
3. BWR Mark II
4. PWR Mark II

The objective of this guide is to provide information that can be used by utilities to improve EHC maintenance practices and procedures. The guidelines will be geared toward providing system engineers and/or maintenance supervisors with the information and guidelines needed to improve site-specific maintenance procedures and processes. This guide contains:

- Descriptions of the electronic systems in EHC.
- Data on system and electronic component failure history for each type of GE-EHC. The history is evaluated to identify trends and document the causes, components, and subsystems involved in the events.
- Summaries of current maintenance practices used by the utilities.
- Guidelines on the maintenance and operation of the systems, which are based on the history of the system electronics and on current utility practices.

The event evaluations indicate that the frequency of problems on units with Mark I systems appears to be increasing, while the frequency for Mark II systems appears to be decreasing. The evaluation indicates that the problems experienced at the various sites cover a broad spectrum. There is no evidence in the event histories or the survey responses that indicate that a substantial portion of the problems encountered across the fleet are caused by one specific device or device class. Therefore, any maintenance program for these systems must be broad based and consider all portions of the system and devices in some detail.

2

GENERAL ELECTRIC EHC CONTROL SYSTEM DESCRIPTIONS

2.1 BWR EHC Mark I Description

2.1.1 Brief Description

The GE Mark I electrohydraulic control (EHC) system is used during plant startup and operation to control the main turbine. Hydraulic oil pressure is used to position various valves of the system to control turbine generator load or speed and acceleration during startup and operation. These include the turbine control valves, intercept valves, and bypass valves. In addition, safety valves such as the main stop valves or the combined intermediate stop valves are controlled to shut off steam flow to the turbine under abnormal operating conditions. The system controls speed or load within the capability of the nuclear boiler to supply steam. In a boiling water reactor (BWR), reactor pressure is controlled by using the turbine as a load for the reactor. The effects of changing reactor pressure on a direct-cycle BWR are:

- An increase in reactor pressure causes some voids to compress and collapse, thus increasing the core moderator content. This increase in moderator content results in more thermal neutrons being available for the fission process, thereby increasing reactor power. A power increase tends to increase the pressure even further; thus, a “snowball” effect is produced.
- A decrease in pressure causes some of the moderator to flash to steam, thus increasing the core void content. This increase in void content results in more neutron leakage, thereby reducing reactor power. A power reduction tends to decrease the pressure even further; a snowball effect is again produced.

2.1.1.1 Reactor and Turbine Power

Because of the effects discussed above, a pressure control system has been developed in which the reactor power is changed first and is then followed by a change in turbine power. Increasing the reactor power causes an increase in both reactor pressure and turbine throttle pressure. A throttle pressure increase requires the turbine control valves to open wider to accommodate the increased steam production. Increasing the turbine steam flow increases the generator output. Reducing the reactor power causes a decrease in both reactor pressure and turbine throttle pressure. A throttle pressure decrease requires the turbine control valves to throttle more, thus decreasing the turbine steam flow. Reducing the turbine steam flow lowers the generator output. Using this control system, the turbine follows, or is “slaved to,” the reactor.

2.1.1.2 Pressure Regulation

Figure 2-1 provides a functional block diagram of pressure regulation:

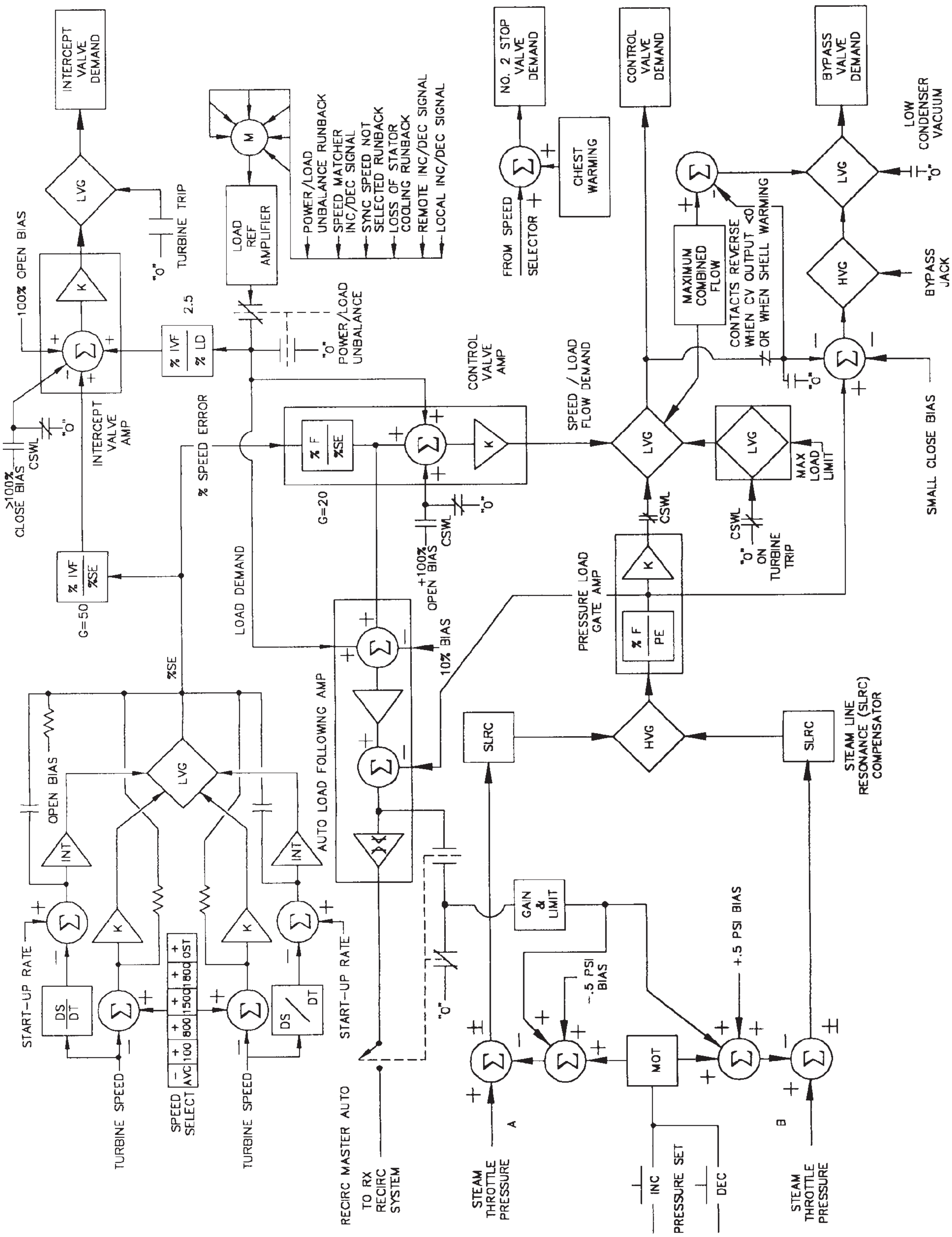

Figure 2-1
BWR Mark I EHC Functional Block Diagram

The turbine throttle pressure is compared to a preselected pressure set point, thus generating a pressure error signal. The pressure error signal is converted into a valve position demand signal, which is sent to the control valve (CV) positioning units. The CVs are hydraulically positioned according to the position demand signal. The amount of steam flow passing through the CVs is proportional to the pressure error.

Assuming a 935 pounds per square inch gage (psig) pressure set point, and a 965 psig turbine throttle pressure at 100% steam flow, a 30 pounds per square inch (psi) error signal exists at 100% power. The proportionality constant (gain) between the pressure error and the percentage of steam flow can be found by dividing the two:

Proportionality Constant (gain)

$$= \frac{100\%\ \text{steam flow}}{\text{the actual throttle pressure minus the pressure set point}}$$

$$= \frac{100\%\ \text{steam flow}}{\text{pressure error}}$$

$$= \frac{100\%\ \text{steam flow}}{30\ \text{psi}} = \frac{3.33\%\ \text{steam flow}}{1\ \text{psi}}$$

In other words, a pressure error increase of 1 psi causes the CVs to open enough to pass 3.33% more steam flow. This relationship has been determined by experimentation. It gives a rapid response, yet is relatively stable. The pressure regulator automatically compares the throttle pressure with the pressure set point, and computes the required valve position to provide the correct amount of steam flow. (The relationship between valve position and percentage of steam flow is determined during startup testing.) If the throttle pressure is ever less than, or equal to, the pressure set point, the CVs will be completely closed.

The first EHC system objective is to position the TCVs, the intercept valves (IVs), and the bypass valves to achieve the turbine speed / acceleration or load that is consistent with the ability of the nuclear boiler to supply adequate steam. The second objective is to control and maintain reactor pressure during plant startup, heatup, and cooldown.

To meet these objectives, the EHC system is comprised of the following subsystems:

- Pressure control unit
- Bypass control unit
- Load control unit
- Speed and acceleration control unit
- Valve flow control unit

2.1.2 BWR Mark I Detailed Description

2.1.2.1 Pressure Control Unit

(See Figure 2-1 for a functional block diagram of the pressure control unit.)

The purposes are to develop a control signal that represents the nuclear boiler steam flow demand and to provide a fast and controlled response to pressure, flow, and pressure set point changes over the entire operating range.

The unit input is the turbine throttle pressure as measured by the redundant pressure transducers. The range is 0 psi–1,050 psi. In order to maintain adequate pressure control during turbine stop valve (TSV) testing, the transducers sense the throttle pressure of a pressure averaging manifold. The two pressure inputs are compared with a preselected throttle pressure set point, thus producing pressure error signals. The desired throttle pressure set point can be varied by operating a motor-driven potentiometer using an increase / decrease push button. The range is 150 psi–1,050 psi. The motor speed limits the rate of set point change to 1 psi / sec. The two identical pressure regulator units ("A" and "B") are redundant, and each is capable of providing adequate pressure control response.

However, to ensure positive control by one regulator, about a 1 psi to 3 psi bias difference is normally calibrated between the "A" and "B" regulators. This pressure regulator configuration protects against the effects of failure of the governing regulator in the low direction, which would cause the regulator output to decrease substantially. A regulator failure in this manner would cause the CVs to close down, thereby increasing reactor pressure. The backup (B) regulator takes control during such a failure mode if the "A" output decreases by about 0.5 psi or more and thus limits the severity of the transient. No backup action is provided if the controlling regulator fails in such a manner as to cause the CVs to open.

Both the regulator outputs are sent through steam line resonance compensators (SLRC) before being sent to a high value gate (HVG). (The SLRC is a notch filter and attenuates resonant frequencies present due to the length of the steam lines and prevents EHC pressure regulator oscillation). The HVG auctioneers the outputs and selects the error signal that calls for the more open control valve position. This signal is then passed on. Normally, the regulator that has been biased has the smallest error signal, and this signal is stopped at the HVG. The pressure error signal leaving the HVG is converted by a gain unit into a percentage of steam flow demand signal.

$$\text{Gain} = \frac{3.33\%\ \text{steam flow}}{\text{pressure error}}$$

The gain unit output is fed to a low value gate (LVG), which is called the “pressure/load” gate. The pressure/load gate compares the percentage of steam flow demand signal from the gain device with several other inputs. The output of the pressure/load gate will be the signal that calls for the most closed CV position. The CV flow control unit receives this demand signal and positions the valves accordingly.

The load limit is set by a variable potentiometer with a range of 0%–100%. This restricts the maximum opening of the CVs to the value selected by the potentiometer. This protects the turbine and/or generator during abnormal operation. For example, if the generator hydrogen pressure was very low and the generator output was limited to 70%, the load limit could be set at 70%. This would “gag” the CVs to a maximum of 70% open, thus limiting the generator load.

When the turbine is tripped (all four stop valves closed), the load limit signal is negated and a zero input is applied to the pressure/load gate. Other inputs to the pressure/load gate are discussed in later sections.

2.1.2.2 Bypass Control Unit Operation

(See Figure 2-1 for the illustration of the bypass control unit.)

The purpose is to generate a bypass valve demand signal in the event that the turbine CVs cannot pass the entire nuclear boiler steam that is produced.

2.1.2.2.1 Operation of the Bypass Control Unit

The output of the gain unit is sent to a summing junction. This percentage of steam flow demand signal is then compared to the turbine CV signal, which is equivalent to the percentage of turbine steam flow. If the steam flow produced exceeds the turbine steam flow, the summing junction output represents a bypass valve demand signal. A small close bias is added to ensure that the bypass valves are positively closed during normal operation. An HVG compares the summing junction output with an input from the bypass jack. During reactor heatup or shutdown, it may be desirable to open a bypass valve(s) a small amount for cooling purposes.

From the HVG, the bypass valve steam demand signal passes to an LVG, which serves three functions. The LVG prevents opening the bypass valves when the condenser vacuum is low (< 7 in. Mercury/Hg); this prevents over-pressurizing the condenser. It also prevents concurrent opening of the bypass and CVs to a value greater than that permitted by the maximum combined flow limiter. The output of the LVG is a bypass valve demand signal, which is then sent to the bypass valve flow control unit.

2.1.2.2.2 Maximum Combined Flow Limiter

The limiter is an adjustable potentiometer that places an upper limit on the total turbine and bypass steam flow demand signal. By restricting the total steam flow demand signal, an excessively fast blowdown is prevented in the event of a large upscale demand signal failure. During power operation, the limiter is set above the load limit to keep it from limiting during normal pressure transients at maximum power conditions.

2.1.2.3 Load Control Unit

(See Figure 2-1 for the illustration of the load control unit.)

The purpose of the load control unit is to develop a steam flow signal that represents the desired load to be placed on the turbine. In addition, a control signal can be sent to the recirculation (recirc) flow control system for automatic load following purposes.

The heart of the load control unit is a motor-driven potentiometer, which develops the desired load signal. This load signal controls the position of the turbine CVs only if it is less than the pressure control signal into the pressure / load gate. The load signal can be varied by several means. First, by manually using an increase / decrease button; second, by use of speed matcher increase / decrease signal; and third, remotely from a central load dispatching station (if authorized).

Several turbine generator conditions require limiting or reducing the turbine load signal:

- Power to Load Unbalance Runback—This is initiated when a comparison of turbine first stage pressure and generator stator amps indicates a mismatch of 40% and a high rate of change exists. The load demand is reduced (run back) to 2% within 45 seconds or until the load rejection conditions clear. In addition, any load signal present is gated to zero when the load reject occurs. In the BWR, since the reactor cannot handle a CV fast closure and resultant pressure increase, a reactor trip is initiated. This action also causes a turbine trip.
- Synchronous Speed Not Selected Runback—Any time that a synchronous speed (1,800 rpm) is not selected, the load signal is run back to 2%. This ensures that, when the turbine is accelerated off the turning gear, the speed and acceleration control unit governs the turbine speed and not the load control unit.
- Loss of Stator Cooling Runback—If stator cooling is lost, the maximum load capability of the generator is 25% of its full-load amperage. The load signal is run back to 25% load within two or three minutes. The load signal from the motor-driven potentiometer is summed with a steam demand control signal from the speed and acceleration network and is sent to the pressure / load gate. This signal would normally be greater than the pressure error steam demand and would not be the controlling signal. The load demand signal is also sent to summing junctions for comparison with a pressure error steam demand signal and a speed error steam demand. If the Recirc Flow Control System master controller is operating in “automatic,” then the output represents a recirc flow signal. (Note: This feature is not used currently.)

2.1.2.4 Speed and Acceleration Control Unit

(See Figure 2-1 for the illustration of the speed and acceleration control unit.)

The purpose is to develop steam demand signals to the CVs and IVs to control the turbine speed and acceleration rate.

2.1.2.4.1 Operation—Turbine Rolling

The process input is the turbine speed as measured by two independent magnetic pickups from a 160-toothed wheel located on the turbine shaft. The pulse rate from the pickup is converted into a voltage signal that represents the turbine speed. Two independent channels provide redundancy. (For simplicity of explanation, only the "A" speed control network is discussed here.)

The speed signal is processed by two separate devices: a speed control section and an acceleration control section. A summing junction in the speed control section compares the turbine speed with a desired speed as selected by the Operator. The speed selections are: All Valves Closed; 100 rpm; 800 rpm; 1,500 rpm; 1,800 rpm; and Overspeed Test. If All Valves Closed is selected, the summing junction output will be demanding the full closure of all the CVs and IVs. If the turbine is at rest and any speed is selected, a large speed error signal is generated and sent to the LVG. This signal would demand full-open CVs unless it is overridden by the acceleration section.

The acceleration section is comprised of three devices: a differentiating unit, a summing junction, and an integrating unit. Differentiating the turbine speed produces an acceleration signal. The summing junction compares the actual turbine acceleration to a desired acceleration that is selected by the operator. The acceleration selections are Slow (60 rpm / min.), Medium (90 rpm / min.), and Fast (180 rpm / min.). At any one time, one of the three acceleration rates is always selected. The acceleration error signal produced at the summing junction is integrated, which converts it into a speed error signal. Both the acceleration control section and the speed control section outputs are speed error signals. If the turbine is at rest and All Valves Closed is selected, the acceleration control section will be demanding full open CVs. However, the speed control section, via the LVG, will keep the valves closed. This occurs because the All Valves Closed position inserts a closed bias.

At the instant that a speed is selected the following occurs: The speed amplifier output demands full open CVs and the Acceleration amplifier takes control, via the LVG, and starts increasing the output of the speed circuit. The output starts from a valve hard closed and ramps toward a value to open the CVs. The IVs will open before the CVs due to the 100% open bias applied to them. As the CVs begin to open, the turbine speed increases and the acceleration output adjusts to control the acceleration rate. The turbine will accelerate at the desired rate until turbine speed approaches 1,800 rpm. Because the turbine requires 2% steam flow in order to keep the turbine running at 1,800 rpm, the load reference units output is low limited at 2%.

When turbine revolutions per minute are approximately 1,800, the speed section output becomes the signal that calls for the more closed CV. The low value gate then selects the speed section output and takes control. The acceleration amplifier can no longer control turbine acceleration, so its output becomes blocked.

2.1.2.4.2 Intercept Valve Regulation

The IVs are normally full open or full closed, but they can be throttled to prevent excessive turbine overspeed. During normal operation, the IVs are kept full open by a summing junction via an LVG. The inputs into the junction include an open bias of 100% that is applied when any speed is selected, a 0% signal from speed error to percent flow regulation, and a variable load reference signal that achieves the desired sequence of operation between the CVs and the IVs during an overspeed condition.

The CV/IV regulation has a gain of 5/2 (2.5×). Its output will vary, depending upon the load selector value. For example, assume that the load selector is set at 100%. The load reference signal to the summing junction will be 250% (100% × 2.5). This particular gain value has been chosen to coordinate the CV and IV response to overspeed. Assuming a 100% steam flow and 100% on the load selector, the CVs will throttle to try to limit overspeed during the first 5% (90 rpm). Due to the large quantities of steam contained in the turbine and separator reheaters, the turbine speed can increase even after the CVs have closed. The IVs throttle closed between 105% and 107% turbine speed. If turbine speed increases to 110%, a turbine trip occurs, thus closing the main stop valves (MSVs) and the combined intermediate stop valves, as well as the CVs and IVs. If the CVs and IVs were not sequenced in this manner, they would both try to control overspeed by throttling the same steam, and turbine speed oscillations could develop.

2.1.2.5 Valve Flow Control Units

Figure 2-2 provides a graphic representation of valve flow control:

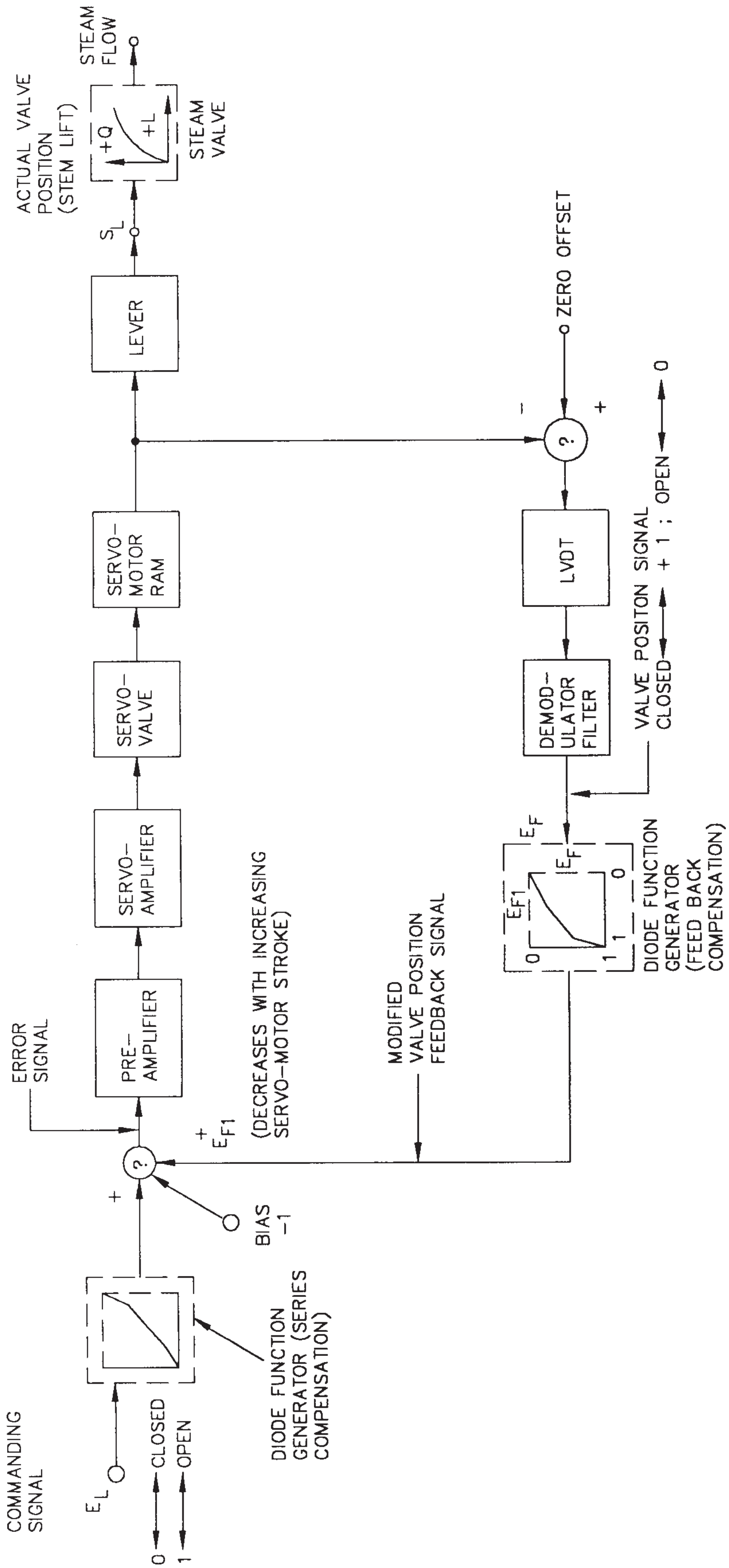

Figure 2-2
BWR Mark I Valve Flow Control Unit

The purpose is to convert a steam flow request into a valve position request and to provide a feedback mechanism for nulling out the demand signal.

2.1.2.5.1 Control Valve Positioning Units

The CV demand is sent to a function generator, which converts this steam flow request into an electrical CV stem lift demand. This signal will be the inverse of the actual valve steam flow characteristics. The stem lift demand is compared to the actual stem lift by a summing junction. Any error existing is sent to a servo amplifier and servo valve for conversion into a hydraulic control signal. The hydraulic control signal varies the hydraulic pressure applied to the valve ram, which in turn positions the valve. A linear variable differential transformer (LVDT) senses the valve stem position and provides the negative feedback necessary for balancing the control signal.

2.1.2.5.2 Bypass Valve Positioning Units

These units are similar to the CV positioning units, except that the bypass valve responses are essentially linear when all valves are considered; therefore, they have no need for a function generator. The sequential bias is used to adjust the bypass valves for opening in sequence, as demanded by the steam flow demand signal.

2.1.2.5.3 Intercept Valve Positioning Units

The IV positioning units are similar to the CV positioning units, except that only IV numbers 1, 3, and 5 can be throttled. Valve numbers 2, 4, and 6 are slaved to numbers 1, 3, and 5 by position switches. Each slave valve opens when the “master” valve reaches 90% open and closes when the master valve is 50% closed.

2.1.2.5.4 MSV-2 Positioning Unit

The unit is similar to the IV positioning unit, except that no function generator is required because precise flow regulation is unnecessary. The unit adjusts an internal bypass valve for steam chest warming. The steam chest is that area between the stop valves and the CVs. The selection of any speed places a large positive bias on the summing junction and causes the MSV-2 to open fully. At 90% open, a position switch sends an “open permissive” to the other three MSVs.

2.1.2.5.5 Chest Warming Functions

Steam chest warming is accomplished by opening the MSV-2 internal bypass. This can be done while the turbine is on the jack. The control valves are biased closed during this time.

2.1.2.5.6 Shell Warming Functions

The shell warming logic will allow the operator to warm the high pressure shell via the MSV-2 bypass valve, with CVs open and intercept valves and intermediate stop valves closed.

2.1.2.6 System Operational Summary

To aid in understanding the EHC pressure control and logic system, the following discussion outlines the sequence of events for reactor startup, commencing with low reactor temperature and pressure and terminating at 100% power.

Plant Startup and Initial Plant Conditions:

- Reactor critical at the point of adding heat; mode switch in Startup
- Moderator temperature: 150°F
- Reactor Pressure: 0 psig
- Pressure regulator set point: 150 psi
- Throttle pressure: zero
- Recirc pumps running in Manual at minimum speed
- Main turbine tripped—all valves closed
- Load limit: zero; maximum combined flow: 50%

Increase reactor power to commence heatup. As the moderator temperature increases above 212ºF, the reactor pressure begins to increase. The pressure set point should be adjusted to be about 50 psig greater than the reactor pressure as pressure increases. This maintains the control system near reactor pressure in the event of a power transient, which could cause a rapid pressure increase if not controlled. Establish the condenser vacuum. Continue increasing the reactor pressure and the pressure set point until the set point is reached (example 935#).

If high pressure turbine shell warming is necessary, reset the turbine. This clears any sealed-in turbine trips and causes the combined intermediate stop valves to open.

- Adjust the load limit potentiometer to allow for CV opening.
- Depress the Off button, then depress the Shell Warming button. As soon as the Shell Warming button is depressed, the CVs open. The acceleration integrator will allow the All Valves Closed signal to increase to zero, so that there will be some speed protection if the turbine should roll off the turning gear. Since at many plants the speed error signal is summed with the MSV-2 signal, the operator must wait for the speed error to approach zero.
- Then depress the Increase button to open the MSV-2 bypass valve and admit steam to the high-pressure turbine shell.
- To terminate shell warming, close the MSV-2 bypass valve and depress the Off button.

Continue control rod withdrawal to increase the reactor pressure. As the throttle pressure exceeds 935 psig, the steam bypass valves begin to open sequentially to pass the excess steam flow. For example, assume that the throttle pressure is 937.5 psig. This produces a +3 psi pressure error in the “A” regulator (+2 psi in “B”). The gain unit converts the pressure error into a percentage steam flow demand:

(Throttle pressure minus pressure set point minus bias) x gain = % steam flow demand. The primary will produce a +10% flow signal and the backup a +6.67% flow signal. The HVG will select +10% and send it to the bypass system. If we assume 5 bypass valves pass approximately 25% steam flow and each valve passes 5% steam flow, then about 2 bypass valves are open at this time. The mode switch should be transferred to Run at 7% power. When a sufficient number of bypass valves have been opened, the turbine can be brought up to synchronous speed. This is accomplished by the following procedure:

- Verify that the turbine is reset and auxiliaries are ready.
- Decrease the chest or shell warming to zero if on.
- Adjust the load limit to 100% Flow and the maximum combined flow to max.
- Select the desired acceleration rate.
- Select 1800 rpm, verifying that the following occurs: MSV-2 ramps open. When MSV-2 is full open, MSV numbers 1, 3, and 4 will open and IV numbers 1, 3, and 5 will ramp open. When they are 90% open, IV numbers 2, 4, and 6 will open.

When all the MSVs and IVs are full open, the speed error from the acceleration network will open the CVs enough to roll the turbine. As the turbine approaches rated speed, the speed error from the speed control section will take control, slowing the turbine until it is stable at 1800 rpm. Using the Load Set Control:

- Adjust the turbine speed.
- Synchronize the generator to the grid.
- Close the generator output circuit breaker.
- Increase the load on the generator by increasing the load set.

As the load set increases, the pressure/load gate will call for an increased CV position. Coincidentally, the bypass valves will begin to close. When the load set output exceeds the value from the gain unit, the CVs will stop opening. The bypass valves should be full closed at this time.

- Maintain the load set at about 10% above the actual turbine load.
- Increase the power (and the pressure) by withdrawing the control rods until the 100% load line is reached.
- Increase the recirc flow manually until a 100% power, 100% flow condition is established.

Final Plant Conditions:

- Reactor critical at 100% power; mode switch in Run
- Moderator temperature: 545ºF (saturation)
- Reactor pressure: 1,020 psig
- Throttle pressure: 965 psig
- Pressure regulator set point: 935 psig
- Recirc pumps running at rated speed
- Load set: 110%
- Main generator output: rated
- Maximum combined flow: 105%
- Load limit: 100% flow

2.2 PWR EHC Mark I Description

2.2.1 Brief Description

In a pressurized water reactor (PWR), reactor power level follows steam demand. To increase power, the steam flow is increased; to decrease power, the steam flow is decreased. When steam demand increases, the heat energy removed from the steam generator increases. As the temperature in the steam generator changes, the heat transferred from the primary loop changes. This causes a temperature change in the primary coolant. The temperature change initiates a power transient that ends when reactor power is equal to steam demand. During turbine startup, steam is throttled to the turbine to bring it up to speed in a controlled manner. The EHC system senses turbine speed and acceleration and positions the steam valves to control speed and acceleration.

In some cases, control of turbine load is given to an integrated control system (ICS). This system is capable of automatically controlling the reactor and its associated steam generator. The system provides an electric megawatt demand for control of the reactor (moving control rods), control of steam generator feedwater (controlling flow rate), and the turbine (providing a load demand signal). This allows a feed forward type of approach to minimize plant disturbances.

The three main objectives of the EHC electronics are to control the load on the turbine when synchronized to the grid, control the loading rate during operation, and control the speed and acceleration during turbine startup.

There are many other automatic and protective functions that the EHC electronics provide. They will be presented later. The EHC system electronics are made up of three basic units that accomplish these overall objectives.

The speed control unit provides for speed and acceleration control. The load control unit provides for load and loading rate control. The flow control unit processes the speed control unit and load control unit signals and develops signals for positioning the steam valves.

2.2.2 PWR Mark I Detailed Description

Figure 2-3 provides a functional block diagram of speed and acceleration control:

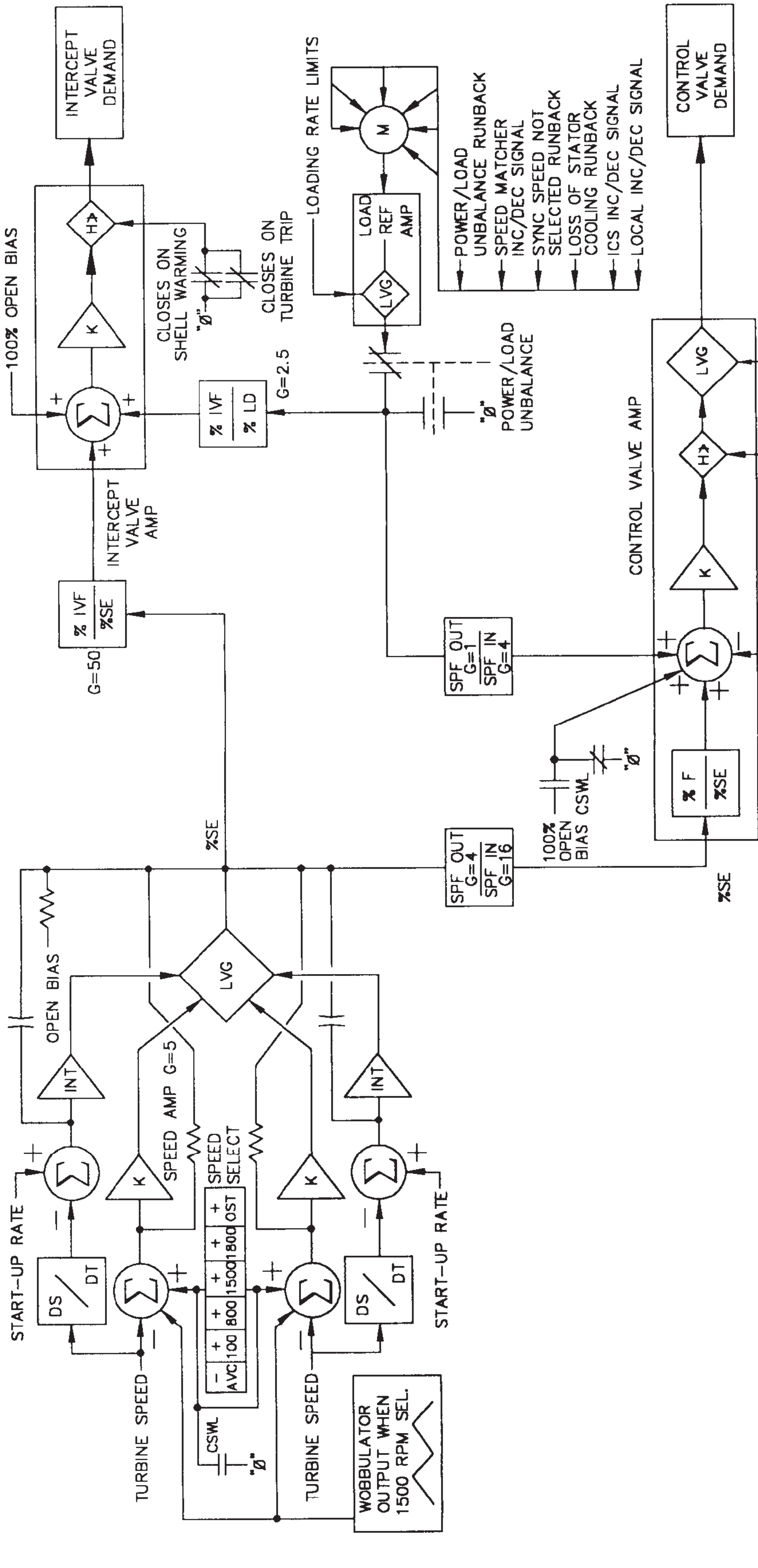

Figure 2-3
PWR EHC Mark I Functional Block Diagram

2.2.2.1 Speed and Acceleration Control Unit

The purpose of the speed and acceleration control unit (SCU) is to develop a speed error signal used by the CV and IV amplifiers to control turbine speed and acceleration. The speed input signals (primary and backup) are developed in the turbine front standard from two of the magnetic pickups that sense frequency from a toothed wheel on the turbine shaft. The turbine speed signal is subtracted from the speed reference signal at a summing junction to develop a speed error signal.

The process input is the turbine speed as measured by two independent magnetic pickups from a 160-toothed wheel located on the turbine shaft. The pulse rate from the pickup is converted into a voltage signal that represents the turbine speed. Two independent channels provide redundancy. (For simplicity of explanation, only the primary speed control network is discussed here.) The speed signal is processed by two separate sections, a speed control section and an acceleration control section.

A summing junction in the speed control section compares the turbine speed with a desired speed, as selected by the operator. The speed amplifier in the speed control section has a gain of 5 as seen from the speed input. The speed selections are: Valves Closed; 100 rpm; 800 rpm; 1,500 rpm; 1,800 rpm; and Overspeed Test.

If Valves Closed is selected, a negative is inserted to the speed summing junction and the output will be demanding the full closure of all the CVs and IVs. If the turbine is at rest and any speed is selected, a positive speed error signal is generated and is sent to the LVG. This signal would demand full-open CVs unless it is overridden by the acceleration section.

The acceleration section is comprised of three sections: a differentiating section, a summing section, and an integrating section.

Differentiating the turbine speed produces an acceleration signal. The summing junction compares the actual turbine acceleration to a desired acceleration, which is selected by the operator. The acceleration selections are: Slow (60 rpm / min.), Medium (90 rpm / min.), and Fast (180 rpm / min.). At any time, one of the three acceleration rates is always selected.

The acceleration error signal produced at the summing junction is integrated, which converts it into a speed error signal. Both the acceleration control section and the speed control section outputs are speed error signals.

If the turbine is at rest and Valves Closed is selected, the acceleration control section will be demanding full-open CVs. However, the speed control section, via the LVG, will keep the valves closed. This occurs because the Valves Closed selection inserts a closed bias.

At the instant that a speed is selected, the following occurs: The speed amplifier output demands full-open CVs and the acceleration amplifier takes control, via the LVG, and starts increasing the output of the speed circuit. The output starts from a valve hard closed value (negative) and ramps towards a value to open the control valves. The intercept valves will open before the control valves, due to the 100% open bias applied to them. As the control valves begin to open, the turbine speed increases and the acceleration circuit's output adjusts to control the acceleration rate due to the integrating action of the circuit.

The turbine will accelerate at the desired rate until turbine speed approaches 1,800 rpm. The turbine requires >2% steam flow in order to keep the turbine running at 1,800 rpm. The load reference unit's output is limited at 2% until a speed selection of 1,800 rpm is made. When turbine rpm is approximately 1,800, the speed section output becomes the signal that calls for the more closed control valve position. The low value gate then selects the speed section's output and takes control. The acceleration amplifier, because it can no longer control turbine acceleration, goes into saturation.

2.2.2.2 Wobbulator

The purpose of the wobbulator is to prevent the unit from running at a constant speed where bucket critical speeds might be experienced. The wobbulator is automatically connected at a speed setting of 1,500 rpm. The circuit produces a voltage that will change the speed slowly, corresponding to a saw-tooth wave shape about the set speed. The circuit is normally set for 6 minute half-cycle time and ±2.8% rated speed magnitude.

2.2.2.3 Load Control Unit

The purpose of the load control unit (LCU) is to develop CV and IV flow demand signals used by the flow control units to control the load and loading rate. The control valve amplifier (CVA) receives three signals used to compute a flow reference demand signal: a speed error from the speed control unit, a load reference signal from the load reference amplifier, and a stage pressure feedback signal (SPF) from first stage pressure. In addition to the above signals, a setback / load–limit / runback circuit will effect the output of the control valve amplifier under certain conditions.

2.2.2.3.1 Load Reference Amplifier/Loading Rate Limit Circuit

The load reference amplifier receives a signal from a rotational variable differential transformer (RVDT). The RVDT produces an output based on its position which is controlled by a motor and load control selector push buttons. A control room meter indicates the load reference value for the operator.

The four push buttons allow local manual control with increase / decrease buttons or remote control of load reference by the plant Integrated Control System (ICS). When ICS IN is pushed, control is given to the ICS and when Manual is pushed control is returned to the EHC system.

In certain cases, the ICS will automatically shift turbine control from ICS to Manual. A loss of stator cooling runback, for example, will shift the EHC control to manual and allow the EHC system to runback the load reference toward 24%. This is accomplished through an interface contact from the ICS.

The motor circuit of the RVDT, in addition to the above, will be controlled to run the load reference back toward 2% if rated speed is not selected or a power to load unbalance condition exists. In addition, the speed matcher circuit will automatically control the load reference output when turned on with the output circuit breaker open. This circuit allows grid frequency to be matched with turbine speed automatically.

The output of the load reference amplifier is also compared with the output of a loading rate limit circuit. A low value gate (LVG) compares the two signals and will only pass the signal calling for a more closed control valve position. Operator selections of 10%/min., 3%/min., 1%/min., and 0.5%/min. are provided. The loading rate limit circuit is disabled whenever the output circuit breaker of the main turbine is open. When the output circuit breaker is closed, the 0.5%/min. rate is automatically selected. In addition, when ICS IN is pressed, a 10%/min. is automatically selected, only to be returned to 0.5%/min. value when control is returned to the EHC system.

The output of the load reference/loading rate limit circuit is directed through power to load unbalance contacts before being sent to the control valve amplifier. These contacts will disconnect the output from the load reference circuit and ground the load reference input to the control valve amplifier when a power to load unbalance condition exists. This shuts the control valves and allows the intercept valves to control turbine speed at 102%.

2.2.2.3.2 Control Valve Amplifier and Stage Pressure Feedback

The purpose of the CV amplifier section (CVA) is to develop a CV flow reference signal used by the flow control unit to properly position the CVs. The three major signals summed at this junction are the load reference signal, the speed error signal, and the stage pressure feedback signal. A 100% open signal is also summed at this junction, but only when shell warming occurs. The output of the CV amplifier is part of an LVG with the load limit circuit. The circuit calling for a more closed control valve position will be in control of the output of the load control unit.

The gain applied to these signals varies, depending on whether stage pressure feedback (SPF) is in or out. There is a direct relationship between turbine first stage pressure and the actual load on the turbine. SPF makes use of this relationship. The SPF signal may be used to improve the linearity of the turbine's response to load changes when not in ICS control.

It is generally not beneficial to have SPF in operation when the ICS control system is operating. This is because the ICS will generally call for closing the control valves upon decreasing steam pressure, and SPF will call for opening the control valves. The ICS is trying to maintain constant steam pressure, and the SPF is trying to maintain constant turbine load. SPF is usually used only during control valve testing. As the control valve under test is being closed, SPF will open the other control valves to maintain turbine load constant.

The SPF control circuit has 3 push buttons. Off turns off SPF action and drives the knob to the out position. Auto automatically inserts SPF action if the turbine is not in ICS control, first stage pressure is above 20%, and throttle pressure is above 95%. Manual allows operator to manually insert SPF action via a control knob.

When SPF is out, the stage pressure signal has a gain of zero. That is, the stage pressure signal is not used; therefore, the EHC system does not respond to changes in first stage pressure. Under these conditions, the load reference signal is summed with a gain of 1, and the speed error signal is summed with a gain of 4. Summing the speed error signal with a gain of 4, after a gain of 5 has already been applied in the SCU, results in a CV regulation of 5% with respect to speed error. For example, if the turbine were to overspeed / underspeed by 5% of rated speed (0.05 x 1,800 rpm = 90 rpm), the CVs would receive a 100% close / open signal to compensate.

When SPF is placed into service, motor positioned ganged potentiometers will change the gains. With SPF in automatic, the stage pressure signal has a gain of 3. In manual, the operator controls gain using the SPF knob. This gain is subtracted from the load reference signal and the speed error signal, which now have total gains of 4 and 16, respectively. The net result of changing the speed error and load reference gains, when stage pressure feedback is in, is that the overall EHC system gain remains unchanged. The CVs now respond to changes in stage pressure.

2.2.2.3.3 Load Limit Circuit

The purpose of the load limit circuit is to send limiting signals to the CVs when the control valve demand signal exceeds the load limit set value.

Under normal circumstances, with no limiting conditions taking place, the output of the load limit circuit is the higher input to the low value gate on the output of the CV amplifier. The CV amp will be in control.

2.2.2.3.4 Intercept Valve

The purpose of the IV amplifier (IVA) is to develop a signal used by the flow control units to position the IVs. The IVA sums the speed error signal with a gain of 5 and the load reference signal with a gain of 2.5. This results in an IV regulation of 2%. That is, if an overspeed occurs at 100% load, the CVs shut in the first 5% of overspeed (90 rpm). The IVs shut in the next 2% of overspeed (36 rpm). Both the IVs and the CVs are shut by 107% overspeed.

A 100% open signal is summed at the junction to maintain the IVs wide-open during normal conditions. When chest / shell warming occurs, a 100% closed signal is summed to cancel the 100% open signal and close the IVs. The output of the IVA is the IV flow demand signal, which is sent to the flow control units.

2.2.2.3.5 Chest/Shell Warming

The chest / shell warming logic will allow the operator to: warm the valve chest only via the MSV-2 bypass valve (all other steam valves closed) and warm the high pressure shell via the MSV-2 bypass valve (with control valves open, intercept and intermediate stop valves closed).

Chest warming is necessary prior to startup in order to match valve metal temperature to initial steam temperature within specified limits to minimize thermal stress.

Shell warming is provided for purposes of matching metal and steam temperatures to minimize thermal stress. Shell warming may also help to alleviate a rotor long differential expansion condition while on turning gear, should it occur. Application of sealing steam tends to warm the HP rotor while the HP shell remains cold. This can cause the differential expansion to approach, and possibly enter, the rotor long red band. Shell warming corrects this condition by heating the HP shell, which causes it to expand with the rotor.

Chest / shell warming is accomplished by pressurizing the HP shell. Pressurization is achieved by closing the intercept and intermediate stop valves, opening the control valves, and admitting steam by controlling the position of the MSV-2 bypass valve.

The chest / shell warming controls are located on the turbine control panel and are used to provide the signal for positioning the MSV-2 bypass valve after the logic is put in the following proper state: 1) turbine reset, 2) close valves selected, and 3) warming rate control potentiometer in zero position or fully counter-clockwise. When these permissives have been met, the operator can warm the chest / shell by advancing the warming rate control slowly in the clockwise direction while observing the throttle pressure meter. If the operator desires to warm the shell and all permissives are met, he must select the shell warm push button prior to advancing the warming rate control slowly clockwise.

To terminate chest / shell warming, select Off push-button. When shell warm is selected, the shell warm light will go on and the chest warming light will go off. The Off light will remain on until the warming control is advanced.

2.2.2.4 Valve Flow Control Units

Figure 2-4 provides a representation of valve flow control:

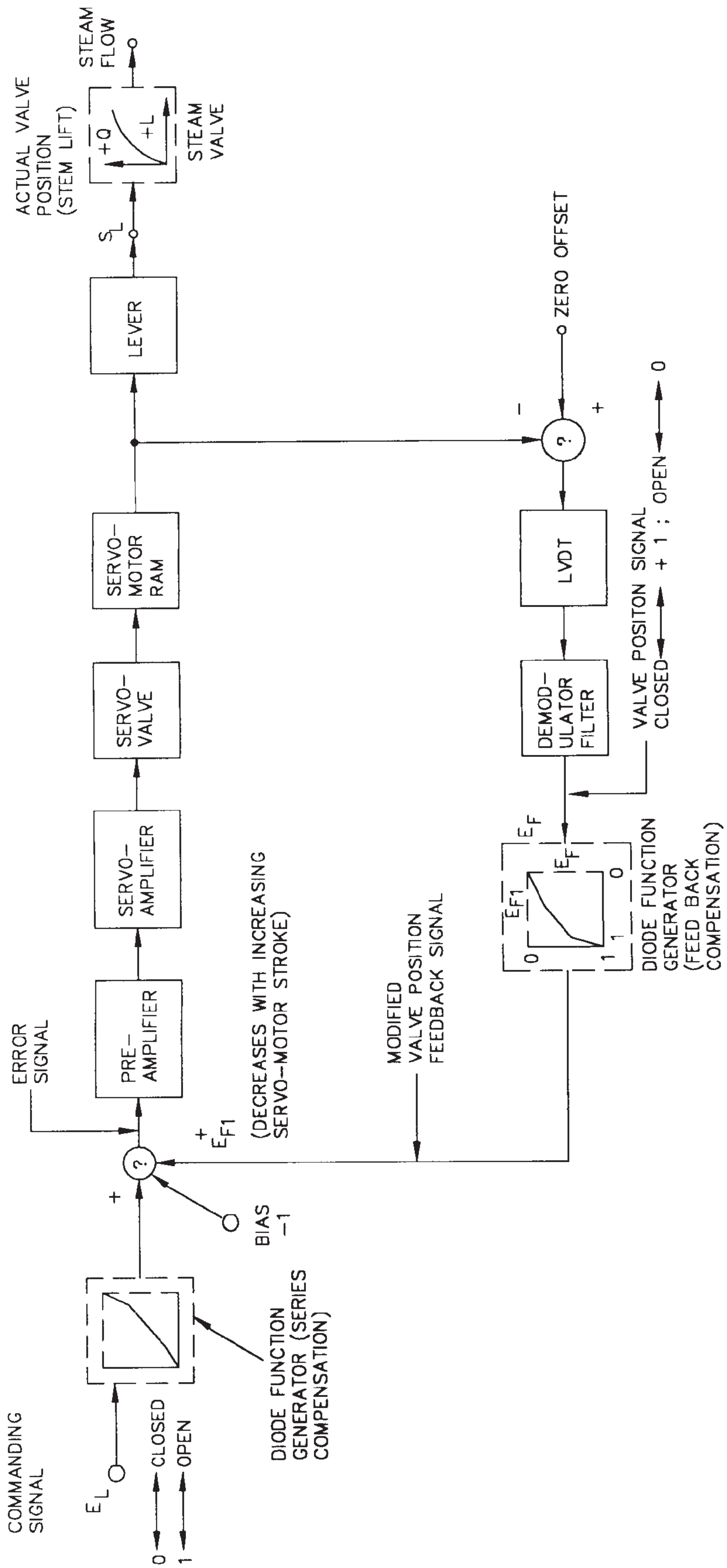

Figure 2-4
PWR EHC Mark I Valve Flow Control Units

The purpose is to convert a steam flow request into a valve position request and provide a feedback mechanism for nulling out the demand signal.

2.2.2.4.1 Control Valve Positioning Units

The CV demand is sent to a function generator, which converts this steam flow request into an electrical CV stem lift demand. This signal will be the inverse of the actual valve steam flow characteristics. The stem lift demand is compared to the actual stem lift by a summing junction. Any error existing is sent to a servo amplifier and servovalve for conversion into a hydraulic control signal. The hydraulic control signal varies the hydraulic pressure applied to the valve ram, which in turn positions the valve. A linear variable differential transformer (LVDT) senses the valve stem position and provides the negative feedback necessary for balancing the control signal.

2.2.2.4.2 Intercept Valve Positioning Units

The IV positioning units are similar to the CV positioning units, except that only IV numbers 1 and 2 can be throttled. Valve numbers 3 and 4 are slaved to 1 and 2 by position switches. As in BWR versions, some units have three low pressure stages. For the example here, the unit uses two. Each slave valve opens when the master valve reaches 95% open and closes when the master valve is 50% closed.

2.2.2.4.3 MSV-2 Positioning Unit

The unit is similar to the IV positioning unit, except that no function generator is required because precise flow regulation is unnecessary. The unit adjusts an internal bypass valve for steam chest warming. The steam chest is that area between the stop valves and the CVs. The selection of any speed places a large positive bias on the summing junction and causes the MSV-2 to open fully. At 90% open, a position switch sends an open permissive to the other three MSVs.

2.2.2.5 Description of Integrated Operation

(See Figure 2-3 for a functional block diagram of integrated operation.)

This figure describes EHC system actions regarding major signal paths and functions. It is a simplified diagram, however, and does not describe all events and details. For example, it can be used to describe a typical turbine start up.

Initial Conditions:

- Reactor critical, NOT, NOP, low in the power range »18%
- Turbine reset, vacuum drawn, shell warming required, on the turning gear
- Loading rate limit—10% / Min. selected
- Load selector—0

- Speed set—close valves
- Starting rate—Fast selected
- Chest / shell warming—Off
- Warming rate—0
- Load limit set—100%

Given the above initial conditions, note that the IVs, CVs, and MSVs will be shut and the ISVs are open. This happens because selecting close valves introduces a large negative value into the speed summing junctions. This causes the SCU to output a large close signal. Inputting a negative speed error signal into the CVA and IVA causes all the CVs and IVs to shut. A contact closes when the Closed Valves is selected to command the MSVs shut. The ISVs open when the turbine is reset.

The Chest / Shell Warming controls are used to slowly warm up the turbine before loading to minimize thermal stresses. The warming rate must initially be decreased to 0 in order to change warming modes; this is an electrical interlock. To begin warming, Shell is selected. When Shell is selected, the ISVs close. The speed reference signal changes from a negative to 0%, and a close bias signal is added to the IVA so that the IVs close. The speed summing junctions sum the turbine speed with the 0% reference signal so that the speed error signal now becomes 0% after a short time. This is done to produce a speed error signal, which detects the turbine rolling off the turning gear during shell warming. The speed error signal is sent to the CVA. The MSV-2 is shut with the warming rate control ready to open MSV-2 internal bypass.

In the CVA, a contact closes, inserting a 100% open signal during shell warming. This causes the CVs to open wide permitting steam flow into the turbine shell. As the warming rate is increased, the internal bypass opens and the actual warming takes place. When shell warming is complete, the warming rate is decreased to zero, closing the bypass, and Off is selected. When Off is selected, the system returns to Close Valves, and a negative signal is again put into the speed reference input. Chest warming is similar, but the control valves stay shut.

At the instant that a speed is selected, the following occurs:

1. The speed amplifier output demands full open CVs, and the acceleration amplifier takes control, via the LVG, and starts increasing the output of the speed circuit.
2. The output starts from a valve hard closed value (negative) and ramps towards a value to open the control valves.
3. The intercept valves will open before the control valves due to the 100% open bias applied to them.
4. As the control valves begin to open, the turbine speed increases and the acceleration circuit's output adjusts to control the acceleration rate due to the integrating action of the circuit.

The turbine will accelerate at the desired rate until turbine speed approaches 1,800 rpm. Because the turbine requires ≅2% steam flow in order to keep the turbine running at 1,800 rpm, the load reference unit's output is set at 2%.

When turbine rpm is approximately 1,800, the speed section output becomes the signal that calls for the more closed control valve position. The low value gate then selects the speed section's output and takes control. The acceleration amplifier, since it can no longer control turbine acceleration, goes into saturation.

With the turbine at 1,800 rpm, the generator is excited and voltage is raised to its proper value. The speed is matched by using the load reference push buttons and the unit is synchronized. As soon as the main circuit breakers are shut, load is increased by the operator with the Load Increase push button to provide minimum load as desired (>110 Mw). As load is increased to about 92 Mw, load control is given to the ICS for further load increases.

2.3 BWR EHC Mark II Description

2.3.1 Brief Description

The electrohydraulic control (EHC and Steam Bypass and Pressure Regulating (SB&PR) Systems) make up one regulating system that provides main turbine speed and acceleration control during startup through the entire speed range, automatic load control, and load limiting in response to preset limits on operating parameters, such as desired load and main steam pressure.

Detection of dangerous or undesirable operating conditions, annunciation of the detected condition, and initiation of proper control response to the condition is provided.

The regulating system monitors the control system, tests valves and controls, provides for pre-warming the valve chest and turbine shell using main steam, and senses and records or indicates turbine operating parameters for operational analysis and malfunction diagnosis.

The above functions are performed and reactor vessel pressure is simultaneously maintained by the positioning of the turbine control valves (TCV), turbine stop valves (TSV), and turbine bypass valves (BPV) during startup, shutdown, and normal operations.

On a BWR system, reactor power, reactor vessel pressure, and turbine load are controlled by the following three major control systems respectively: Reactor Recirculation Flow Control System, Steam Bypass and Pressure Regulating System.

2.3.1.1 Electrohydraulic Control System

One of the major design features of the direct-cycle boiling water reactor (BWR) is the passage of nuclear-generated steam through the turbine system. Most of the steam generated by the reactor is normally accepted by the turbine. The operation of a BWR demands that a pressure regulator concept be applied to maintain a constant turbine inlet pressure. Load following capability must be accomplished by variation of the reactor recirculation flow.

Pressure changes in a direct-cycle boiling water reactor can have a pronounced effect on reactor power. If pressure is increased in a BWR during power operation, steam voids—which contributes significant negative reactivity to the core during power operation—collapse, increasing core moderator content. This increase in moderation results in more thermal neutrons being available for the fission process, thereby increasing reactor power. As reactor power increases, pressure tends to increase even further and a snowball effect is produced. The opposite effect occurs when reactor vessel pressure decreases; some of the moderator flashes to steam because the reactor vessel is in a saturated state. This flashing increases the void content in the reactor vessel, resulting in more neutron leakage and a reduction in reactor power. This reduction tends to decrease reactor pressure even further.

Because of this effect, a pressure control system was developed in which reactor power is first changed, followed by a change in turbine generator output. An increase in reactor power causes an increase in both reactor vessel and turbine throttle pressure. This pressure increase is due to an increased heat generation by the reactor core, producing more steam without a subsequent increase in steam flow rate. The throttle pressure increase is sensed by the pressure control system and signals the turbine control valves to open wider, accommodating the increased steam production. This increase in turbine steam flow compensates for the reactor vessel pressure rise and increases generator output.

Reducing reactor power decreases reactor vessel pressure and turbine throttle pressure. The control system responds to the decrease in throttle pressure by throttling the turbine control valves in the closed direction, decreasing turbine steam flow. Reducing steam flow stops the steam pressure decrease and lowers generator output. Using this control system, the turbine follows or is slaved to the reactor.

Turbine throttle pressure is compared to a desired pressure set point generating a pressure error signal, which is converted into a valve position demand signal and sent to the control and bypass valves. These valves reposition hydraulically based on the demanded position. The amount of steam flow passing through the control valves is proportional to the pressure error signal.

The pressure set point is nominally set at 920 psi. At 100% power and 100% steam flow, turbine throttle pressure is 950 psig and a 30 psi pressure error signal exists. As stated previously, steam flow through the turbine control valves is proportional to the pressure error. In order to determine the proportionality constant (gain) between steam flow and pressure error, all that is needed is a simple calculation: The regulation value is 3.33% steam flow per 1 psi error.

In other words, a 1 psi pressure error causes the control valves to open to pass 3.33% steam flow. This relationship was determined by experimentation and gives a rapid response that is relatively stable. The pressure regulator compares the throttle pressure with the pressure set point and generates a valve position demand signal based on this error. If throttle pressure is ever less than or equal to the pressure set point, the control and bypass valves are fully closed.

Note that the relationship between reactor vessel pressure and percent steam flow is not linear, and this is primarily due to pressure drop across the flow restrictors, MSIVs, and stream line piping, which is proportional to the flow squared.

The turbine pressure regulator, in maintaining constant turbine inlet pressure, operates the steam bypass valves, such that a portion of nuclear boiler rated flow can be by-passed when operating at steam flow rates above that which can be accepted by the turbine or during plant startup and shutdown.

The steam bypass and pressure regulating system, in conjunction with the electrohy-draulic control system accomplish the following control functions: Control turbine speed and turbine acceleration, operate the steam bypass system to keep reactor vessel pressure within limits and avoid large power transients, and control main turbine throttle pressure within the proportional band setting of the pressure regulator.

2.3.2 BWR EHC Mark II and SB&PR Detailed Description

Figure 2-5 provides a functional block diagram of the EHC Mark II and SB&PR detail:

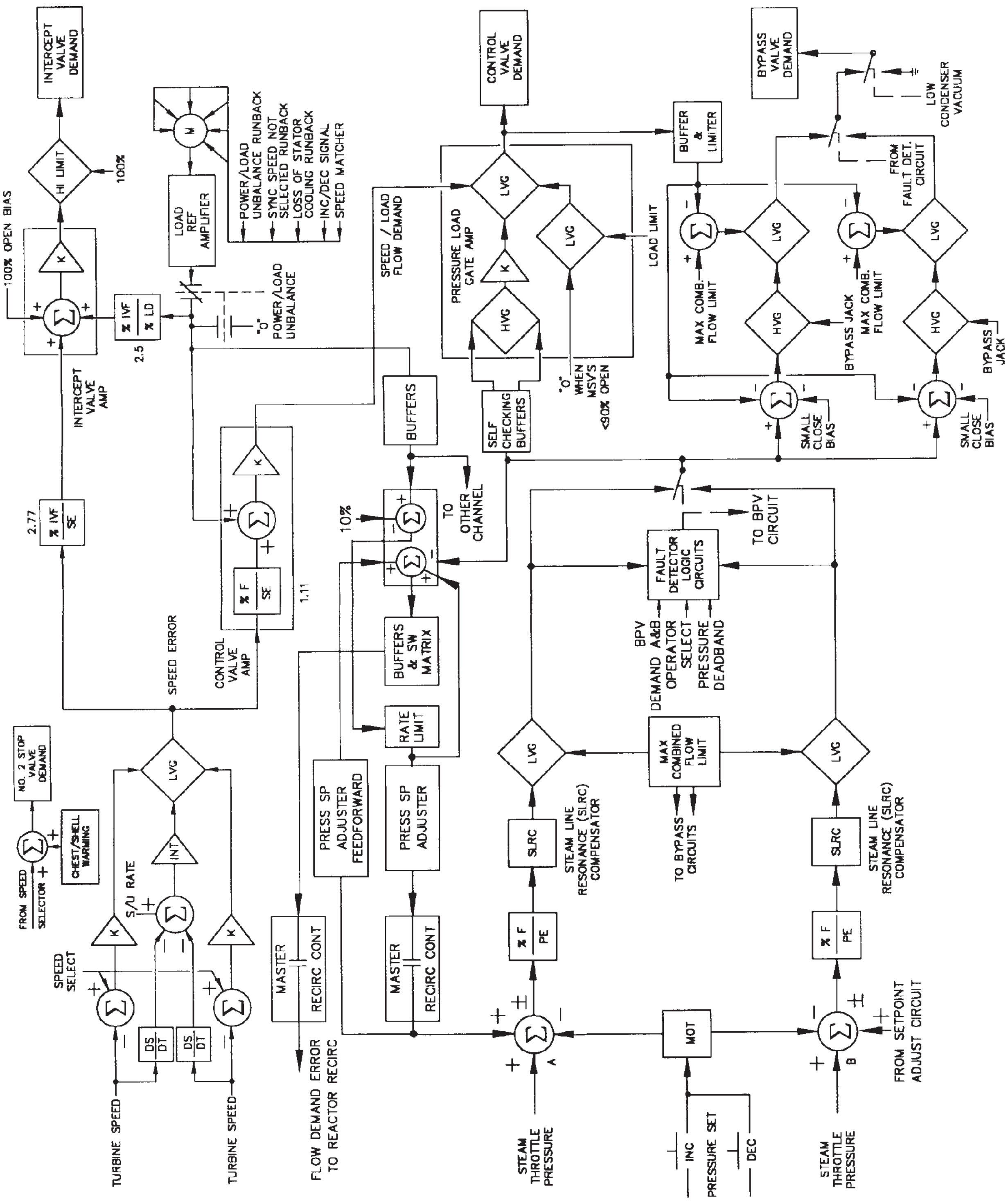

Figure 2-5
BWR EHC Mark II and SB&PR Functional Block Diagram

2.3.2.1 Steam Bypass and Pressure Regulating System

The steam bypass and pressure regulating system (SB&PR) maintains reactor vessel pressure within an operational band by simultaneously positioning the main turbine control valves and steam bypass valves during plant startup, shutdown, and normal operations. If reactor vessel steam output exceeds turbine load requirements, the SB&PR system opens the steam bypass valves to divert the excess steam directly to the main condenser.

A pressure equalizing header upstream of the turbine stop and control valves provides a single pressure connection point for piping connecting the main steam lines to the steam bypass valves. Each bypass valve exhausts directly to one of the main condenser shells. A pressure reducer is provided in each of the bypass valve exhaust line connections to the condensers. The total capacity of the bypass valves is about 25% to 35% of rated steam flow at 950 psig.

Two pressure transducers monitor main steam pressure through an averaging manifold connected to each steam line near the turbine stop and control valves. The pressure transducers provide redundant signals, equivalent to main steam pressure, to the pressure control cabinet in the control room. The steam pressure at this point is referred to as the turbine throttle pressure.

The pressure control cabinet compares turbine throttle pressure to a manually adjusted pressure set point and a maximum combined flow limit from the SB&PR sub-panel on the bench board. The resultant combined flow demand signal normally positions the turbine control valves to maintain an essentially constant throttle pressure and meet turbine speed-load requirements, such as during startup, shutdown, sudden load reduction, or turbine control or stop valve testing; the steam bypass valves sequentially open to bypass the excess steam directly to the condenser.

The pressure control cabinet also initiates fast opening of both bypass valves to the full-open position within 0.1 seconds after a turbine stop valve closure or a control valve fast closure. A bypass valve opening jack control on the SB&PR sub-panel provides manual control of the bypass valves.

Bypass valve positioning signals from the pressure control cabinet activate electrohydraulic controls that proportionally position the bypass valves. Hydraulic fluid is supplied, under pressure, to the electrohydraulic controls by a separate bypass valve hydraulic power unit. Servovalves and fast opening solenoid valves supply the hydraulic fluid to the bypass valve actuators according to the bypass valve positioning signals.

Both steam bypass valves are automatically closed on loss of pressure control cabinet power or loss of hydraulic fluid pressure. To prevent overpressurization of the main condenser, a pressure switch in each condenser shell will trip all bypass valves closed if vacuum in the condenser decreases to approximately 7" Hg. A condenser vacuum trip reset push button and a low vacuum indicating light are provided.

2.3.2.2 Electrohydraulic Control System

The main turbine's GE Mark II electrohydraulic control system (EHC) controls the position of the main turbine's steam valves in response to the SB&PR pressure control signal or a turbine speed / load demand signal. The EHC flow control unit, which positions the turbine control valves, receives inputs from the SB&PR pressure control unit, the turbine speed control unit and the turbine load control unit. The flow control unit consists of electronic circuitry, an electrohydraulic servovalve, hydraulic actuator, and a linear position transducer, which makeup the "control pac" assembly on the turbine control valves (TCVs). The speed and load control units also control the position of the turbine intercept valves (IV).

The protective function of the EHC system consists of two major subsystems: the mechanical-hydraulic trip system and the electrical trip and monitoring system. When a signal is received from sensing devices, indicating that a condition exists requiring a turbine trip, either of the two subsystems will act to release the hydraulic fluid pressure in the valve actuator control pacs, rapidly closing all turbine steam valves.

The purpose of the protective system is to detect undesirable or dangerous operating conditions of the turbine-generator, take appropriate trip actions, and provide information to the operator about the detected conditions and the consequent actions. In addition, means are provided for testing all testable equipment and circuits.

A simplified signal flow diagram of the protective system is shown in Figure 2-6:

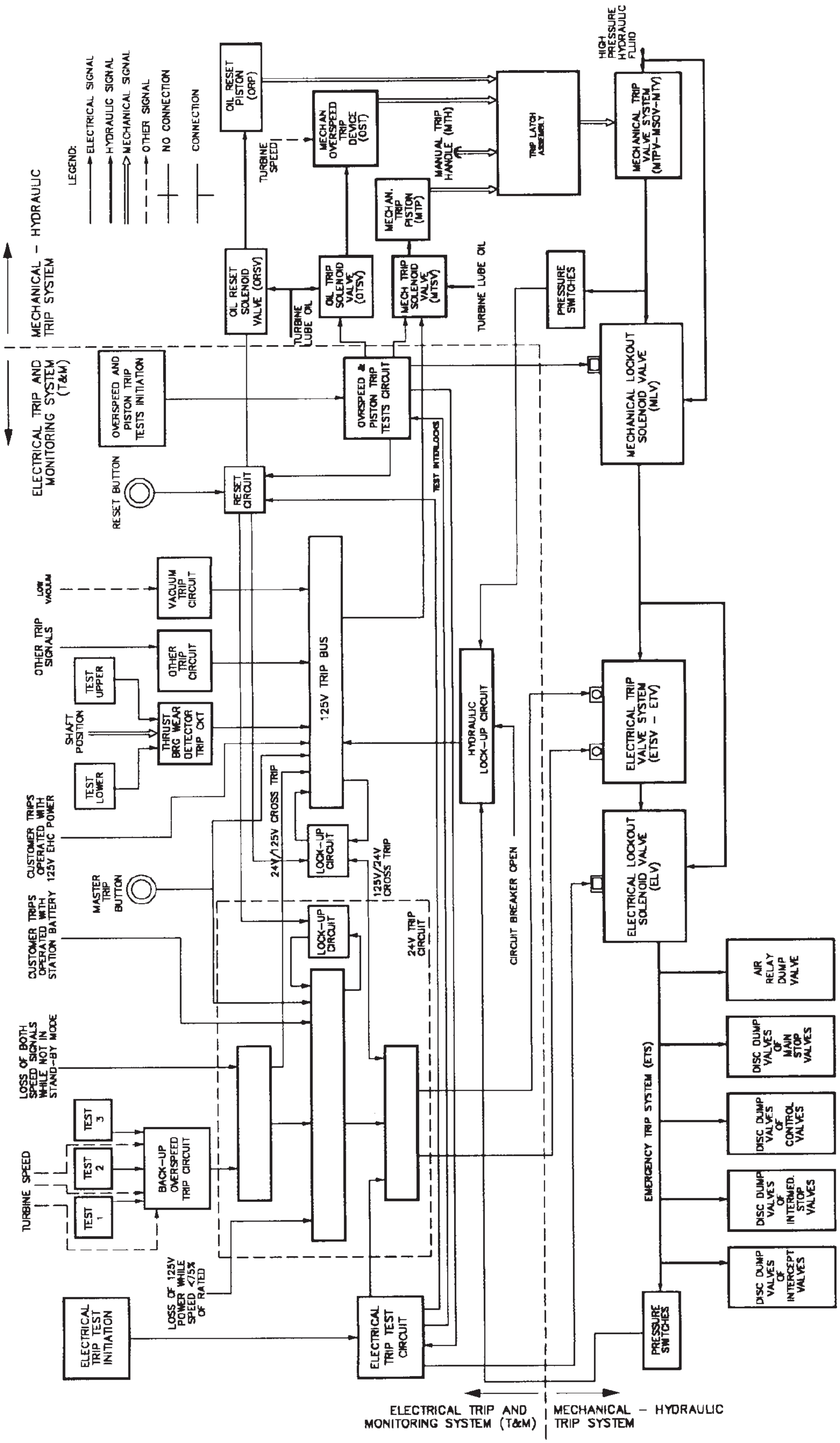

Figure 2-6
Emergency Trip System

The emergency trip system (ETS) is the high-pressure fluid system that, when in the reset or pressurized state, permits all steam valves to open in the presence of opening signals from the EHC. When in the tripped or depressurized state, it overrides all opening signals, trips the main and reheat stop valves, the control valves, and the intercept valves directly by way of their disc-dump valves, and trips the extraction check valves through the air relay dump valve. The principal output function of the protective system is to control the state of the ETS.

2.3.2.2.1 Mechanical Hydraulic Trip System

Figures 2-7 and 2-8 provide additional diagrams of the trip system:

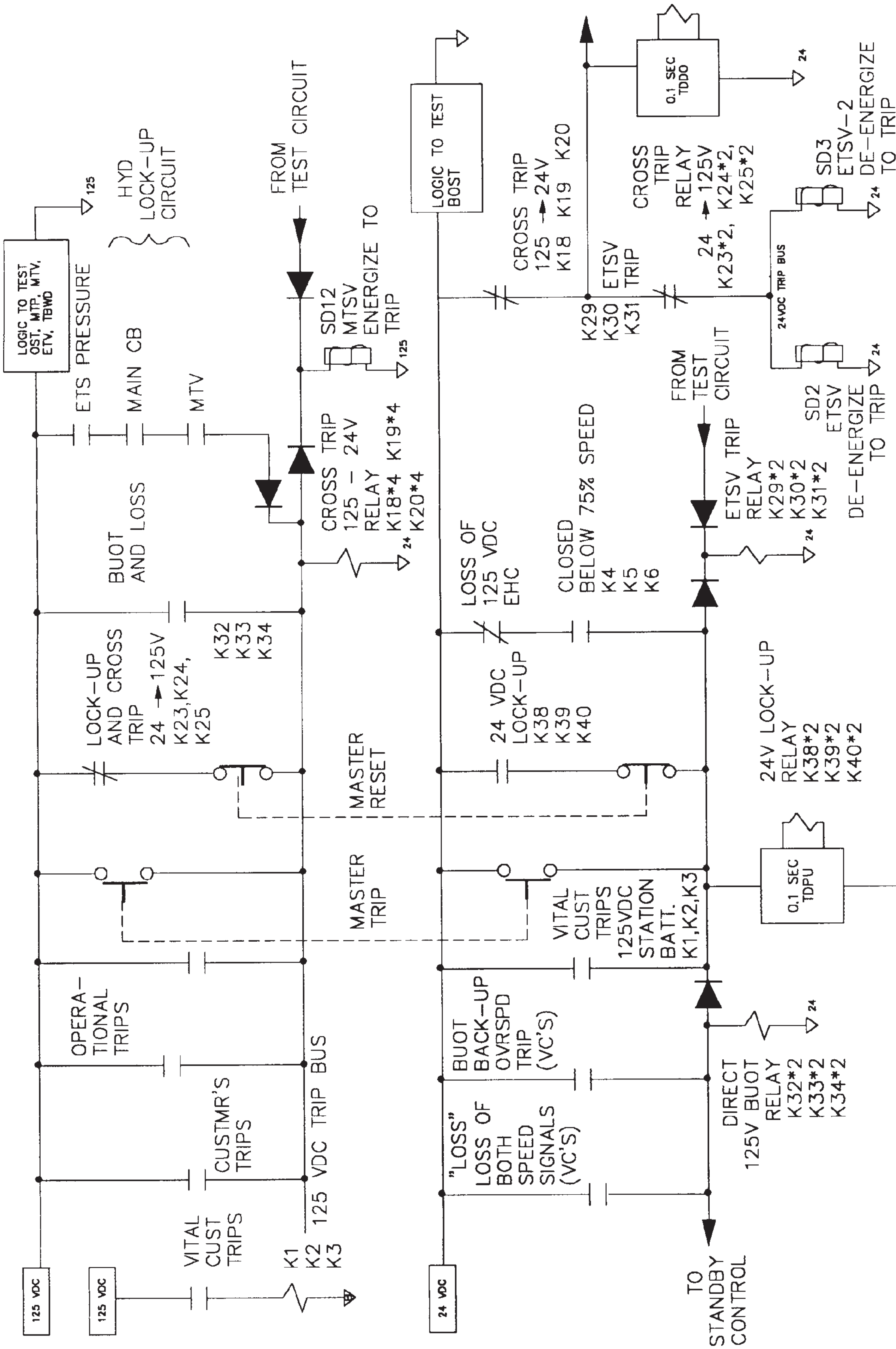

Figure 2-7
Simplified Trip and Monitoring

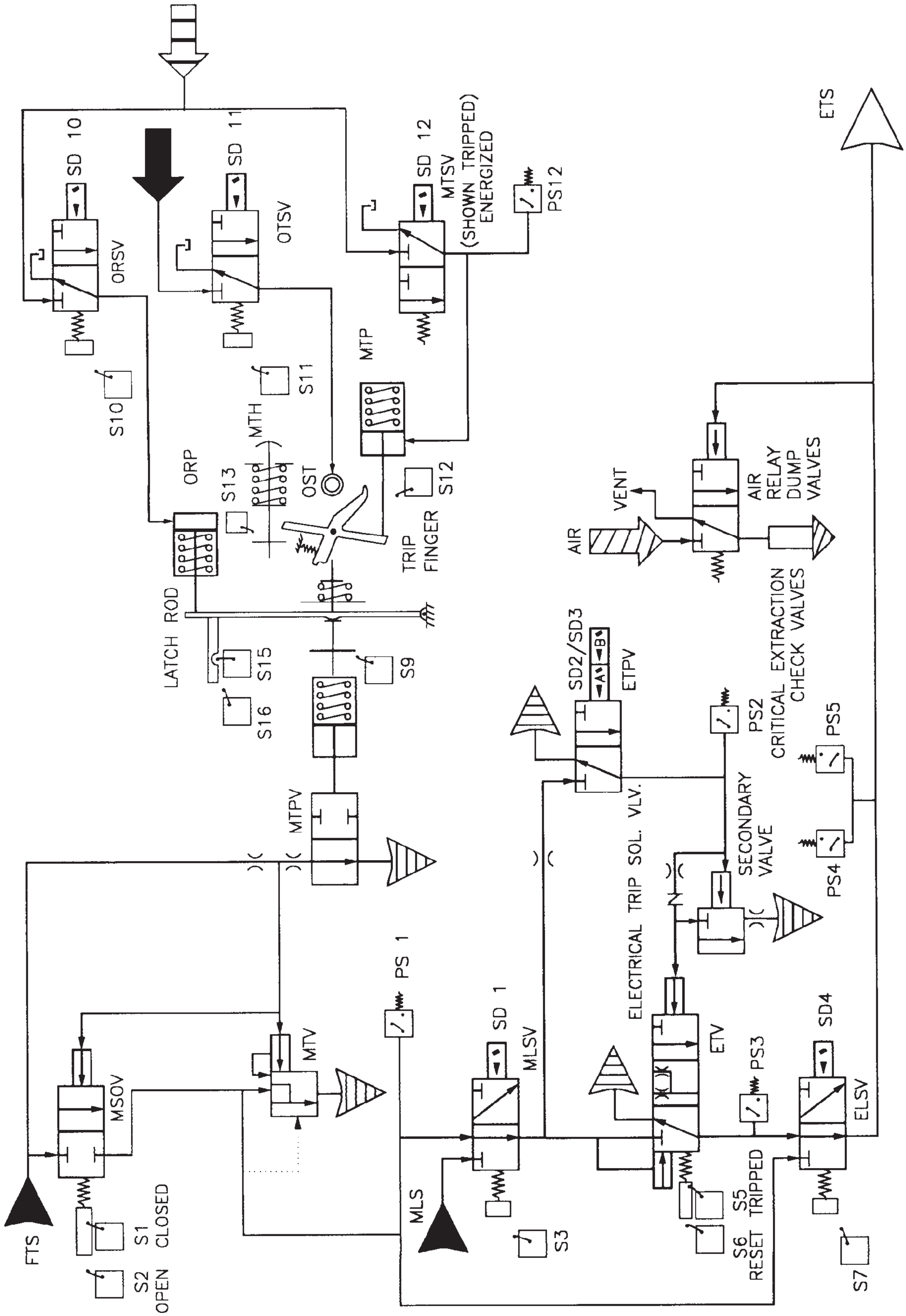

Figure 2-8
Trip System Simplified Diagram

The ETS is pressurized from the high-pressure hydraulic fluid supply through the following chain devices, all components of the mechanical-hydraulic trip system:

- Mechanical shut-off valve (MSOV)
- Mechanical trip valve (MTV)
- Mechanical lockout solenoid valve (MLV)
- Electrical trip valve (ETV)
- Electrical lockout solenoid valve (ELV)

The MSOV and MTV are controlled hydraulically by the mechanical trip pilot valve (MTPV); when their pilot lines are depressurized, these valves shut off their input line and drain their output line, tripping the ETS.

The MLV is controlled electrically by the T&M; when energized, it bypasses the MSOV and MTV, permitting these two valves and two of the three signal paths that actuate them to be tested without tripping the ETS.

The ETV is controlled hydraulically by the electrical trip solenoid valve (ETSV); when its pilot line is depressurized, this valve shuts off its input line and drains its output line, tripping the ETS.

The ELV is controlled electrically by the T&M; when energized, it bypasses the ETV, permitting this valve and the signal path that actuates it to be tested without tripping the ETS.

In order to trip the ETS, any tripping signal has to actuate one or both of the MTPV or the ETSV. Each of these two cases will be examined separately.

1. MTPV Actuation

This valve is operated mechanically by the trip latch rod, which is tripped (that is, allowed to move under the influence of a charged spring to a position where the MTPV is tripped) by the trip finger.

The trip finger is operated by the:

- Mechanical overspeed trip device (OST)—This is actuated during an overspeed of the turbine exceeding the OST setting, or at rated speed during a mechanical overspeed trip test. During this test, the T&M energizes the oil trip solenoid valve (OTSV), which admits lubrication oil to the OST, causing it to trip. A coordinated actuation of the MLV prevents the ETS from tripping.
- Mechanical trip piston (MTP)—This is held in the reset position by turbine lube oil pressure. The piston is allowed to trip by action of a spring when the oil pressure is lost or when the oil is shut off by the mechanical trip solenoid valve (MTSV). This valve is energized by the T&M during a 125V trip, as it will be defined later, or during a MTP test. In the latter case, a coordinated actuation of the MLV prevents the ETS from tripping.

- Manual Trip Handle (MTH)—There is no provision for testing the MTH under lockout conditions. An MTH test will result in an actual trip. The trip latch rod, once tripped, latches mechanically and remains in the tripped position even after the condition that caused it to trip has been cleared. It is reset by the reset mechanism, consisting of:
  1. The Oil reset solenoid valve (ORSV)—when energized by the T&M actuates the oil reset piston
  2. The Oil Reset Piston (ORP)—resets the trip latch rod and the MTPV, which in turn resets the MSOV and MTV

2. ETSV Actuation

This valve has two 24 VDC solenoids, which are normally energized when the ETSV is in the reset state. The valve trips when both solenoids are de-energized. Failure of one solenoid will not cause a spurious trip. The solenoids are connected to the T&M and are de-energized during a 24V trip, as will be defined later, or during an electrical trip test. In the latter case, a coordinated actuation of the ELV prevents the ETS from tripping.

The mechanical-hydraulic trip system includes a number of pressure switches and limit switches that are connected to the T&M and provide information about the state of the various components (valves, piston, trip latch rod, and MTH).

2.3.2.2.2 Electrical Trip and Monitoring System (T&M)

Figure 2-9 provides an outline of the system monitor panel:

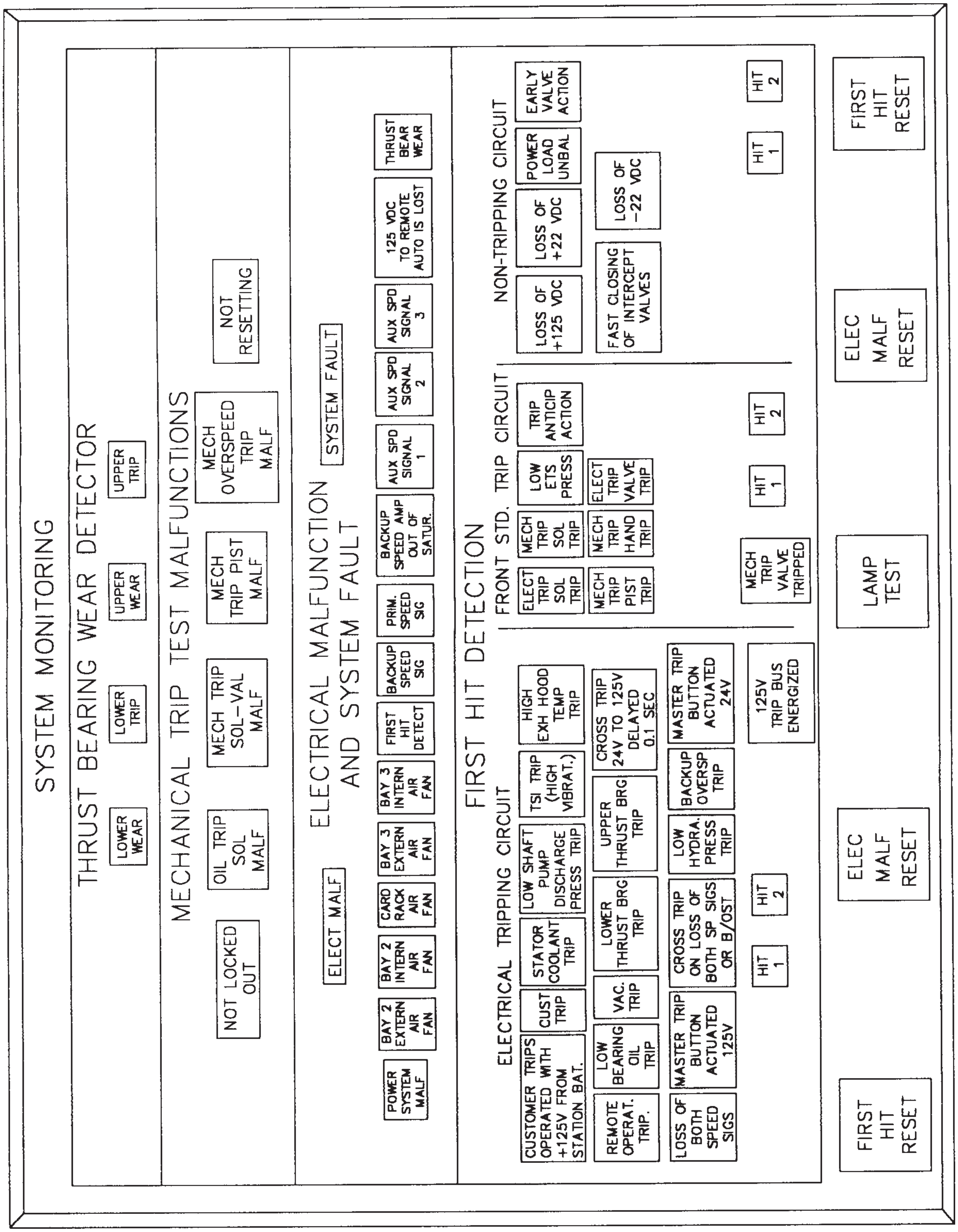

Figure 2-9
System Monitor Panel

The principal function of this part of the protective system is to connect all external trip signals (except the tripping signals from the OST and MTH, which act directly on the mechanical-hydraulic trip system) to one or both of the MTSV and ETSV after suitable modifications by logic circuits. Each of these valves is independently capable of tripping the ETS.

The incoming trip signals are arranged into two groups:

1. Signals external to the EHC cabinet—These cause 125V Trips; that is, they activate the 125V trip bus and energize the MTSV directly. In addition, the 24V trip circuit is indirectly operated through a set of relays (cross trip), and the 125V trip bus is locked up after a short time delay.

When the generator circuit breaker is open and the MTV and ETS are tripped, an additional lock-up circuit is established through pressure switch contacts. During a MTP test, the MTSV is energized without activating the l25V trip bus, the cross trip circuit, and the lock-up circuits.

2. Signals internal to the EHC cabinet—These cause a 24V trip, that is, they de-energize the ETSV solenoids through a set of relay contacts and lock-up the 24V trip circuit through another set of relay contacts. The first set of relays is also operated during an electrical trip test; in this case, the lock-up circuit is not activated and the situation is cleared once the cause producing it is removed without necessitating any positive resetting action.

Of the signals internal to the EHC cabinet, the Loss of Both Speed signal, and the back-up Overspeed Trip signal energize, in addition to the tripping and the locking relays, a third set of relays which cross trip the 125V trip bus. The other three signals that cause a 24V trip do not energize these cross trip relays; however, of these, the master trip button causes a 125V trip through a separate contact. The customer, at its option, can do the same for customer trips energized by the 125V station battery. Only the loss of 125 VDC when speed trip is below 75% of rated inevitably produces a 24V trip alone. A loss of 24 VDC de-energizes the ETSV solenoids, causing a 24V trip and cross-trips the 125V trip bus.

In summary, all trip signals to the T&M, except the loss of 125 VDC, and—if the customer so chooses, the customer trips operated with station battery—activate two independent paths throughout the T&M and the mechanical-hydraulic trip system and provide redundant trip signals to the ETS.

When the condition that caused a trip has cleared, the EHC can be reset by depressing the Reset button on the turbine panel. This will break the lock-up circuits and reset the MTV through the reset mechanism. The Reset button must be held down until the Reset light comes on to assure the ETS pressure has been re-established.

T&M also contains the logic for testing the trip devices (mechanical overspeed, mechanical trip piston and electrical trip tests). When one of these tests is initiated, the T&M logic provides a sequence of signals to the appropriate lockout, trip, and reset valve solenoids and receives feedback signals that allow it to sense the status of the mechanical-hydraulic trip system after each step and whether the test was successful.

Each of the three back-up overspeed trip circuits can be separately tested without causing an actual trip. These circuits, as well as many other trip circuits of the T&M, are arranged in a two out-of-three logic system.

The thrust bearing wear detector is tested, via an automatic system, from the control panel.

Finally, the T&M system contains logic for the display of the status of the ETS, mechanical-hydraulic system, and the T&M itself, logic for annunciation and first hit detection of tripping and other abnormal conditions, and provides switching signals for control functions to other sections of the EHC and for customer use.

2.3.2.3 Plant Communications

The plant communications subsystem is divided into two sections. One is for analog signals, and the other is for digital (relay) type signals. The purpose of the system is to isolate circuits of the EHC system from circuits external to the system. The isolation provides protection for EHC if there should be a failure external to the system from being coupled into the EHC electronics and causing problems. The analog section contains isolation buffers with the input powered by EHC and the output powered from a separate source. The digital isolation consists of relays and or contacts that provide the isolation of signals needed by other systems.

2.3.2.4 Electrical Power System

The electrical power system for the Mark II electrohydraulic control system (EHC) is divided into two distinct portions: the AC portion, consisting of the incoming power from the power grid and the permanent magnet generator, and the DC portion, derived from the AC portion through power supplies. A further refinement in the AC portion is the ability to change the power source from the primary to a secondary source in case of failure of the primary.

The power supply bay contains eight main power supplies in vertical arrangement, two, one-tier card-racks, a circuit breaker each for the house power and primary power, three main transformers, several small auxiliary supplies, and one large diode steering board. All the converters for AC input and DC output are located here. Inserted into the front door is the power supply monitoring panel.

Figure 2-10 outlines the general arrangement of the main power system. It shows, in block form, the sources of the AC power, the changeover mechanism, the AC power use, the DC power conversion, and the DC power use. The two systems are completely redundant for extreme reliability.

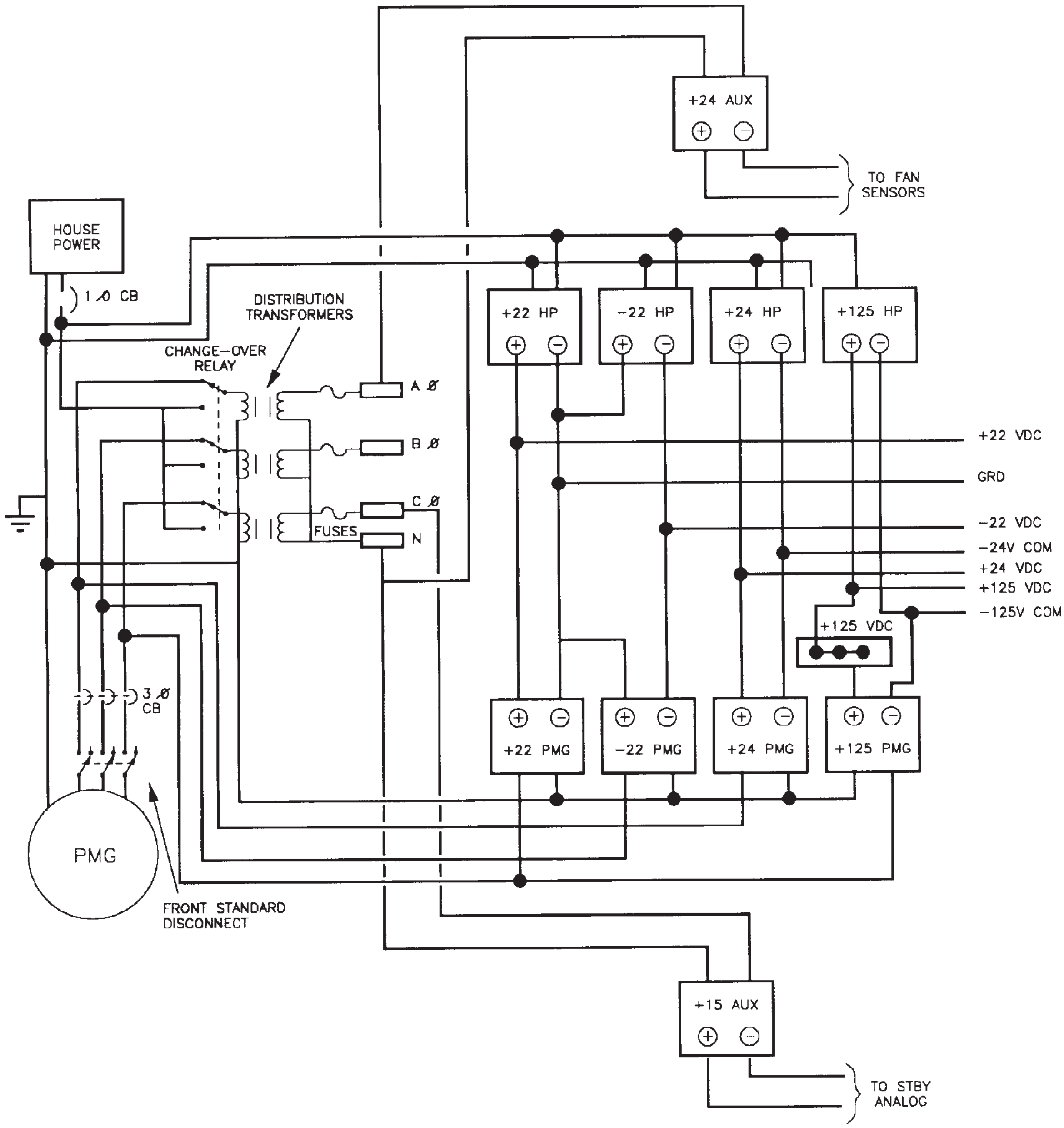

Figure 2-10
AC / DC Power and Ground

The AC portion of the electrical power system consists of the permanent magnet generator (PMG), the incoming house power, the main breakers, the main transformers, and a host of smaller devices that distribute, protect, and use the AC power.

The primary source of power is the PMG, mounted on the turbine shaft. This generator has a capacity of 7.5 Kw, 120 VAC, 60 Hz, 3 phase, ample for any power requirements. This power is fused at the front standard and protected in the EHC Cabinet by a 3-phase circuit breaker. Because the PMG will not be operative at speeds below 1,600 rpm, it cannot be used to power the control system at startup. The PMG is the primary source of power only while the turbine is running.

The secondary power source, and the one used to start the turbine, is supplied by the plant power grid, the house power (HP). This is brought into the EHC cabinet at 120 VAC, 3 Kw, 60 HZ, 1 phase. It is protected by a circuit breaker located next to the primary circuit breaker.

These two power sources are interconnected through a changeover relay so the HP can be used to start the turbine and then the sources be switched to the PMG while the turbine runs. A voltage sensing relay senses the output voltage of each phase of the PMG; when each phase is above 110 VAC energizes the changeover relay. If any one phase of the PMG falls below 105 VAC, the sensor de-energizes the changeover relay and restores the EHC system to secondary power.

The main transformers provide electrical isolation between the power sources and the using equipment. They are connected in parallel for use on the secondary power (HP) and across a phase on primary power (PMG). All AC power to the EHC system (except the PMG power supplies) passes through these transformers. It is used to power the cabinet cooling fans, the drive motors, fast-acting solenoids, and some transducers.

The AC portion of the electrical power system is rugged and reliable. Adequately sized components have been used throughout, and a comprehensive program of testing has assured their reliability.

The DC portion of the electrical power system consists of the four main power supplies and their attendant distribution buses. Since these are the “heart” of the system, they will be explored in greater detail.

The DC portion comprises four separate voltage buses, +22 VDC, -22 VDC, +24 VDC, and +125 VDC. They are supplied by completely redundant power supplies, two per bus. Thus, a failure of one power supply will not de-energize that particular bus.

These power supplies receive their AC input power from differential sources. One set of four, named the house-power supplies, are permanently connected to the secondary source and act as the secondary DC supply. The other set of four, named the PMG power supplies, are permanently connected to the primary source, the PMG, and act as the primary source.

These supplies are connected, each to its voltage buss on the secondary side, through built-in power diodes. These diodes make it possible to use the supplies in a remote sense mode.

The supplies, each for its bus voltage, are set a slight voltage difference apart. Due to the built-in diodes, one supply, the primary PMG, supplies all the current while the other, the secondary, is idling. Should a malfunction occur to the primary supply, the bus voltage will drop the slight voltage offset, and the secondary supply will then furnish all the bus current with no interruption of service.

The description applies to each of the buses. The major difference is in the bus voltage. The +22 VDC and -22 VDC buses have a common ground, while the +24 VDC and 125 VDC systems “float” with respect to common ground. This requires the use of “ground detectors.”

Built into the power supplies are overvoltage and overcurrent protection systems to shut them down in case of internal faults. These protection systems are connected through indicators to the power supply monitor panel for visual information to the operator.

Each of the power supplies has two cooling fans to ensure an adequate flow of cooling air across the major heat-producing components. The supplies are designed to operate at full load with no derating, and with only one fan operating.

The +22 VDC and -22 VDC systems share a common “ground,“ and a short-circuit on either system will indicate by loss of power. The +24 VDC and +125 VDC systems do not have a ground, neither with themselves nor with each other. A short-circuit to the common ground will not be detectable, causing the cabinet to be at a dangerous potential relative to others. Therefore, a ground detection system is built into the +24 VDC and +125 VDC systems.

This ground detector gives a visual indication to the operator should one side of these two voltages inadvertently be connected to common. It is up to station personnel to then clear the short.

Three variable voltage power supplies are included in the card-rack. These provide power for the three pressure transducers only. They are 28 VDC power modules regulated between 21 VDC and 25 VDC; regulation better than 0.1%, at 40 ma. These cards are adjusted at cabinet test for +25 VDC and can be adjusted in the field, if necessary.

Information on how the DC portion of the power system is performing is furnished to the operators by the power supply monitor panel. (See Figure 2-11.) Information is displayed, by meters and lights, of the bus voltages, output currents, and supply status.

The +22, -22, +24, and +125 VDC bus voltages are displayed with small, expanded scale meters. These meters indicate the voltage of the major buses at all times.

Two sets of meters indicate the bus current of the major buses. The first set shows the currents delivered by the PMG supplies when they are controlling; the second set are for the HP set. As stated previously, the two supplies do not share load current. Thus, which power supply set is supplying load current can be determined at a glance and action taken, if needed.

The power supply history is also displayed by the monitor panel (see Figure 2-11).

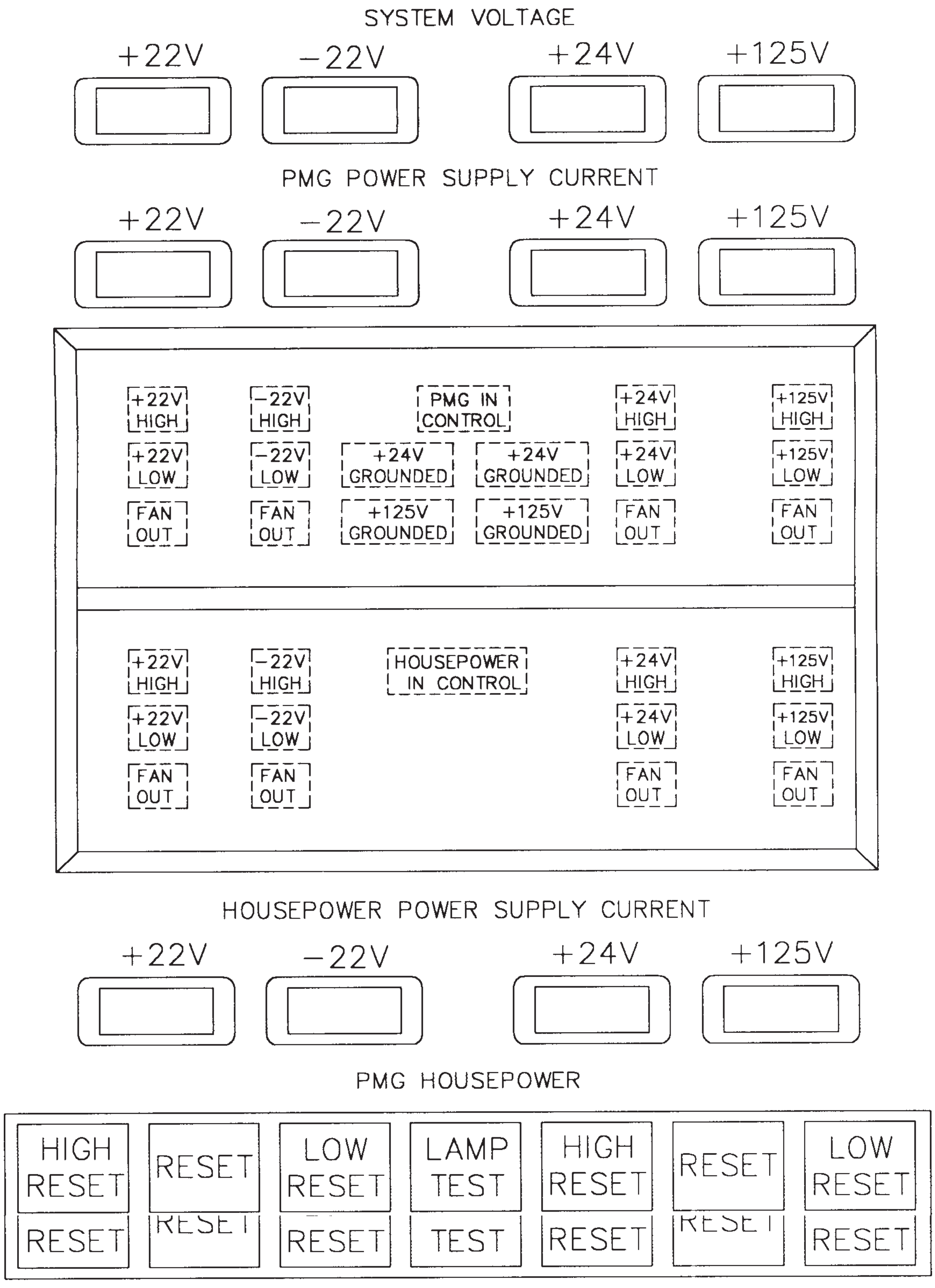

Figure 2-11
Power Monitor Panel

The information displayed is any overvoltage, any undervoltage, or any fan stoppage.

All of these indications except the last can be reset if the power supply has returned to normal operation. Fan operation is automatic. Resetting is accomplished by pressing push buttons located on the panel.

One bit of information concerning the AC system is displayed on the monitor panel. This is whether the HP or the PMG is controlling the AC power. Below 1,500 rpm, the HP furnishes all the AC current and voltage, and the legend House Power In Control is displayed. Above 1,500 rpm, the PMG furnishes the needed AC current, and the legend PMG In Control is shown.

The power supply bay contains two, one-tier card-racks. These racks hold the cards associated with Loss of Voltage, Over-Under Voltage, Meter Adjust, Ground Detection, and Transducer power.

2.3.2.5 EHC/SB&PR System Interaction

Turbine speed and acceleration control is normally provided by the pressure regulator, which controls steam throttle valve position to maintain constant reactor vessel pressure. The turbine speed governor or load circuitry overrides the pressure regulator on an increase of turbine speed or loss of generator load. Excess steam is automatically bypassed directly to the main condenser by the pressure controlled bypass valves.

Provision is made for matching nuclear steam supply to turbine steam requirements. As load demand increases, the pressure control unit sends a proportional signal to the reactor recirculation flow control system, which causes an appropriate increase in recirculation flow to increase reactor core thermal power. The increased reactor power will provide more steam to the turbine, meeting the increased load demand. A similar, but decreasing, change will occur in response to a load demand decrease. Automatic load following operations are not permitted.

2.3.3 Major Component Description and Location

The major components of the electrohydraulic control system and steam bypass and the pressure regulating system are: pressure control cabinet, bypass valve assemblies, bypass valve hydraulic power unit, EHC speed control unit, EHC load control unit, EHC standby control unit, EHC valve positioning units, EHC emergency trip system, turbine front standard trip system, EHC trip logic systems, and EHC hydraulic power unit.

2.3.3.1 Pressure Control Unit

The pressure control cabinet is a signal processing cabinet located in the control room. Redundant channels of processing circuitry are provided within the cabinet. The operator selects the controlling channel with the Channel A / Channel B Select switch on the SB&PR section of the control panel. Fault detection circuits monitor both channels at selected signal output points. The outputs of both channels are continuously monitored by three fault detection networks. Within the fault detection circuitry, the average of the channel A and B outputs is computed. This average is time delayed and then compared to the instantaneous value of each channel output. A fault is detected if the difference between the A or B channel output is equivalent to 17% rated steam flow (approximately 5 psi) from the time-delayed computed average signal. If a fault exists, the channel that has deviated the most from this time-delayed average is assumed to be the failed channel, and, if the failed channel is in control, a switching matrix automatically informs the operator of the channel failure and switches to the operative channel. In addition, the circuitry locks out any further fault signals and locks out manual channel selection from the control panel until the circuitry is reset by the operator. Local circuitry and controls are provided for testing this fault detection circuitry. Placing a pressure regulator in test, at the control room back panel, signals the fault detection circuitry that the channel in test has failed and automatically switches to the opposite channel.

The fault detection networks in the pressure regulator network, bypass valve demand, and auto load following circuits are similar in design and function. Each inputs to one common switch matrix to automatically select the alternate channel in all the signal networks.

A throttle pressure signal is sent to the pressure regulator, where it is amplified and sent to a summing amplifier. An input representing the pressure set point is also applied to the summing amplifier. This input comes from a motor driven potentiometer or up / down counter that is controlled by the pressure set point Increase and Decrease switches on the control panel. A single motor or up / down counter drives the pressure-set point pots for both channels A and B. The output of the summing network is the Pressure Error signal. This pressure error signal is proportional to the turbine steam flow demand signal. When the proportionality constant (gain) of the pressure regulator is applied to this signal, it represents the total flow demand signal to the turbine control and bypass valves. The pressure control cabinet gain causes a 3 psi pressure error to be equivalent to a 10% demand in steam flow.

The maximum combined flow limiter limits the sum of turbine flow plus bypass flow to a preset value. The set point is adjusted by a 2-gang potentiometer (one for each channel) mounted on the control panel. The limiter's task is first to limit the total flow demand and second to restrict bypass flow demand so that turbine flow plus bypass flow does not exceed the limiter set point. The bypass flow limit is generated by subtracting the turbine steam flow demand from the maximum combined flow limit. The total flow demand limit is established by comparison of the pressure error / flow demand signal and the maximum combined flow limit pot signal is a low value gate arrangement. If the maximum flow limiter is overriding either the bypass valve demand or the total steam flow demand signal, the Max Comb. Fl Lmt In Cont light on the control panel is illuminated. The signals from the flow demand combined flow limiters are fed through a switch matrix that selects the channel requested by the operator if no fault exists in the pressure regulator circuitry.

2.3.3.2 Bypass Control Unit

The bypass valve demand signal is normally derived by calculating the difference between total steam flow demand signal and turbine steam flow reference signal (from the pressure/load low value gate) inputs to the bypass valve demand summer. The turbine flow reference signal to the bypass valve demand summer is high and low limited by the bypass valve demand flow limiter. This ensures that the bypass demand reference signal (turbine steam flow) is always a meaningful measure of actual turbine steam flow when the turbine control valve demand is less than zero, or greater than that for all CVs wide open (approximately 108%). The third signal into this summer is a small closing bias (approximately 3%) that prevents bypass valve "hunting" (small random opening) caused by signal noise. The output of the summer amplifier represents the calculated bypass valve demand signal.

The bypass valve demand signal is sent to a high value gate (HVG) where it is compared with the signal from the bypass valve jack. The bypass valve jack is controlled by the bypass valve opening jack controls. The jack provides a means for manually operating the bypass valves. The output of this HVG is compared to the bypass flow limit, and the lower value signal is passed through fault detection circuits to the switch matrix. The output of this low value gate is limited (10% limit) to prevent excessive bypass valve servo currents demanding further valve opening when all the bypass valves are full open. From the switch matrix, the output signal is passed through the main condenser low vacuum low value gate. If condenser vacuum is above the set point of 7" Hg vacuum, the demand signal from the switch matrix is passed to the bypass valves. If vacuum is low, a zero signal (to close all bypass valves) is passed to the bypass valves positioning unit. This interlock prevents overpressurization of the main condenser. This circuitry is all part of the bypass control units.

There are two other signals generated by the SB&PR system. One signal is the total steam flow demand signal passed to the pressure/load LVG, which is part of the turbine control system. Here it is compared with the turbine speed/load demand signal and, whichever signal is calling for the smallest opening demand of the control valves, is sent to the control valves. The turbine load set signal from the EHC load control unit is generally set higher (usually 7%) than the actual steam flow demand called for to ensure pressure control is maintained by the control valves.

2.3.3.3 EHC Speed Control Unit

The speed control unit of the EHC system receives two speed signals, compares them to an operator-set speed reference signal (selections are: All Valves Closed; 100 rpm; 800 rpm; 1,500 rpm; 1,800 rpm; and Overspeed Test) to produce two speed error. The speed control unit also differentiates the primary speed signal to produce an acceleration error signal (selections are 60/90/180 rpm/min. these are Slow, Medium, and Fast), which is integrated and low value gated with the two speed error signals to produce an output to the load control unit. The backup speed amplifier signal is normally biased, such that the primary speed amp signal will control. The signal out of the low value gate is the signal that requires the smallest turbine control valves opening demand. The speed set point and acceleration set point are selected by push buttons on the Turbine Speed / Load Control panel in the control room.

The speed control unit is provided with a wobbulator circuit, which slowly varies turbine speed slightly (50 rpm) above and below the selected speeds during startup to avoid extended operation near resonant frequencies at which excessive vibration may occur. This circuit is automatically placed into service for selected speeds of 1,500 rpm. The turbine speed will vary in sinusoidal fashion.

Two magnetic speed sensors provide the primary and backup speed signals for the speed control unit. The sensors are located over a toothed wheel in the main turbine front standard. As the toothed wheel is rotated, the speed sensor generates an AC signal proportional to turbine speed. A 160-toothed wheel generates a 4,800 Hz signal at rated speed. Two speed signals are provided for reliability. If the speed signal is lost, then the backup speed signal provides the turbine speed signal. If the turbine is on acceleration control and one of the speed signals is lost, then the actual acceleration rate will be double that selected. If both speed signals are lost, then a turbine trip results unless the EHC system is in the standby control mode.

There is also a backup overspeed trip circuit. This trip will occur if the mechanical overspeed trip circuit fails. It is set about 1% higher than the mechanical overspeed trip. It can be tested on-line by disabling the trip and lowering the trip setting to 99% of the normal speed. This causes the trip circuits to function, and the trip is tested.

The line speed matcher circuit in the speed control unit is used to simplify synchronization of the generator with the grid. Once the turbine is at rated speed, depressing the Speed Matching Selected push button will command the line speed matcher to automatically synchronize (match frequencies) the turbine generator frequency with the grid. The operator must manually close the main generator output breaker to complete paralleling to the grid. The line speed matcher is not normally used.

2.3.3.4 EHC Load Control Unit

The load control unit receives: a speed error signal from the speed control unit, a combined flow demand signal from the SB&PR pressure control system, signals relating to turbine operating parameters from other EHC subsystems, and demand signals from the operator to compute a flow reference signal for the turbine control valves and the combined intercept valves.

Central to the operation of the load control unit is the load set motor. The purpose of this motor is to position a variable differential transformer, which generates a Load Reference signal used in computing the final value of desired load. The operator can control the position of the load set motor and thereby set the load reference signal by using the Load Selector Increase or Decrease push buttons on the EHC control panel.

The line speed matcher, when selected, positions the load set motor to synchronize the generator frequency with the grid. In the line speed match mode, the Load Selector Increase / Decrease push buttons remain functional.

The load set runback circuitry repositions the load set motor to approximately a 2% demand position when certain abnormal conditions are detected that require a reduction in load. It takes approximately 45 seconds for the runback circuitry to drive the load set from the full-load setting to the 2%, no-load setting. If the condition that initiated the runback clears, the runback will stop, leaving the load set at that position. When a runback occurs, power to the load set motor increase circuitry is interrupted to prevent stalling the motor. Any time rated speed is not selected at the EHC control panel, the load set motor is runback to ensure that the speed control unit controls turbine acceleration rate.

One of the signals that initiates a load runback is power / load unbalance. The power / load unbalance circuit measures HP turbine exhaust pressure, which is proportional to turbine steam flow, and compares it to the generator stator current, which is proportional to generator load. The power to load unbalance can be tested on-line by the operator. The power / load unbalance signal also gates the output signal from load reference to the IV and CV amps to “0.” The power / load unbalance set point is 40% of full-load and a high rate of change. That is, generator load equal to or greater than 40% less than turbine steam flow (turbine power) and a load change equivalent of going from rated to 0 in < 35 mS. The control valves, and in some cases the intercept valves, are fast-closed to prevent an overspeed condition from tripping the turbine. This circuit was originally designed to allow the turbine to stay on-line without tripping on a loss of load. However, in a BWR, when the control valves fast close, a pressure spike is induced in the reactor that causes a power excursion. For this reason, the BWRs cause a scram signal to be generated to shut the plant down when a power to load unbalanced condition exists.

To protect the main generator windings, a load set runback is initiated when a loss of stator cooling condition occurs. It is initiated if generator load (stator current) is greater than 25% and a low pressure condition on the cooling water inlet to the stator windings occurs, or a high temperature on the outlet exists or a low flow condition exists in the system. The runback will continue until the loss of stator cooling condition clears or the load set reaches 25%.

Another signal that causes the load set motor to runback is a load limit signal to the load set runback circuitry that is more than 4% less than the load reference signal established by the load set motor position. In this case, the load set motor will runback only until it is again within 4% of the load limit signal. Power to the load set motor Increase circuit is interrupted anytime a load set signal exceeds the load limit signal by more than 2%.

2.3.3.4.1 Intercept Valve Control Signal

The flow reference signal from the intercept valves is generated by the EHC system by summing the load reference signal (with IV / CV gain applied) with the speed control unit speed error signal (with IV gain applied). In addition, bias equal to 100% opening demand is added to this reference signal to ensure that the intercept valves remain full-open during normal operating transients. The intercept valves are normally fully open but throttle in the close direction during turbine overspeed conditions.

For turbine overspeed conditions from 100% to 105% of rated speed (load set at 100%), the control valves throttle from full-open to full-closed, to prevent further overspeed. Due to large quantities of steam contained in the turbine cross around piping and moisture separators, turbine speed may increase even after the control valves have closed due to steam supplied to the LP turbines. The intercept valves throttle in the close direction from 105% to 107% turbine overspeed to prevent further admission of steam to the low pressure turbines.

If the control and intercept valves were not sequenced in this manner, they would both try to control overspeed simultaneously by throttling, and, as a result, turbine speed oscillations could develop as turbine speed was reduced and the intercept valves re-opened, admitting cross around steam to the low pressure turbines.

2.3.3.4.2 Turbine Control Valve Control Signal

The control valve flow reference signal is generated from the pressure / load low value gate. This low value gate selects the lowest of 3 inputs: the turbine speed / load demand, the combined flow demand signal from the SB&PR system, or the operator controlled load limit signal.

2.3.3.4.3 Turbine Chest/Shell Warming

Pre-warming of the steam chest (the area between the main stop and control valves) and the HP turbine shell and rotor prior to rolling the turbine off the turning gear is provided by the chest / shell warming feature of the load control unit. This feature is operator-controlled, via push buttons on the EHC control panel. Selection of the chest warming enables the internal bypass valve of turbine stop valve No. 2 to open, based on a signal from the warming rate potentiometer, allowing steam to enter the piping between the stop valves and control valves. The steam warms the control valves and returns to the main condenser through the control valve drains. The rate of pre-warming is operator-controlled by means of the Chest / Shell Warming Increase or Decrease push buttons, which regulates the signal from the warming rate potentiometer to the No. 2 stop valve bypass valve positioning unit. Selection of Shell Warming enables opening of the control valves and allows steam to enter the HP turbine shell by applying a 100% open bias to the control valve amp at the same time removing the CV flow reference limit from stop valve closure at the pressure / load LVG. To ensure pressure control via the bypass valves, the control valve flow reference to the bypass valves demand amp is switched to zero. During shell warming, the intercept valves are biased closed and the intermediate stop valves are commanded to shut to prevent steam from entering the LP turbines and possibly rolling off the turning gear. A zero speed reference signal is input into the speed reference section of the speed control unit to limit speed in the event of accidental roll-off during shell warming. Speed error is switched to the MSV-2 amp, along with the warning rate pot signal to control MSV-2 bypass valve position. Selection of either chest or shell warming eliminates the 100% open bias normally applied to open the MSVs when a speed is selected.

2.3.3.5 EHC Standby Control Unit

The standby control unit provides capability for the operator to manually establish the control valve flow reference signal, via the standby load set potentiometer, overriding the speed and load control unit signals. the standby control unit is enabled only when the EHC System is in the Standby mode. Once the Standby mode is selected, via a push button on the turbine control panel, the control valve flow reference signal is established by the operator via the standby load set potentiometer on the EHC section of the control panel. The standby control unit provides a 100% open bias to the CIVs and the MSVs to open them in the standby mode.

Since the standby control unit is completely manual, the status of the turbine generator system must be continuously monitored by the operator while in the Standby mode. In the Standby mode, the input to the pressure/load low value gate, which normally comes from the load control unit, is now controlled by the standby load set potentiometer. Pressure control (from the SB&PR system) still controls the position of the turbine control valves, unless the standby load set point becomes the low signal into the pressure/load LVG. There are only two means of turbine overspeed protection when the standby control unit is in control. First, the backup overspeed trip is reduced to 105% (from 111%) or 1,890 rpm to become the primary means of overspeed protection. Second, the normal overspeed trip at 110% becomes the backup overspeed protection in the Standby mode of control.

2.3.3.6 Valve Flow Positioning Units

The valve positioning units of the EHC system convert the flow reference signals from the load control unit into position demand signals for the control valves, intercept valves, and stop valve No. 2 internal bypass valve. The valve positioning unit for a control valve is typical of all valve positioning units, except for the sequential bias and function generators that are particular to the control valve and intercept valve positioning units. The flow control units function the same as those block diagrams shown earlier in this maintenance guide. A non-linear function generator converts the flow reference signal into a position demand signal. This signal is compared with the actual valve position, and the position error signal is sent to a positioning servovalve.

The relationship between percent of rated steam flow and percent of valve stroke is not linear. The control valve flow reference to valve position function generator compensates for this. Because the stop valves and intermediate valves do not normally modulate, they have no function generators associated with their positioning units.

2.4 PWR EHC Mark II Description

2.4.1 Brief Description

In a pressurized water reactor (PWR), reactor power level follows steam demand. To increase power, the steam flow is increased; to decrease power, the steam flow is decreased. When the steam demand changes, the pressure in the steam generator changes. Since it is a saturated system, the temperature in the steam generator changes with pressure. As the temperature in the steam generator changes, the heat transferred from the primary loop changes. This causes a temperature change in the primary coolant. This temperature change initiates a power transient that ends when reactor power is equal to steam demand. Many other transients occur in the primary loop. However, the main point is that reactor power follows steam demand. The EHC system controls the steam demand by positioning the steam control valves to control the load on the turbine. In this way it controls reactor power.

If steam demand is changed abruptly, steam pressure changes abruptly. If the magnitude of the change is large enough, severe shrink and swell occurs in the steam generator and the primary plant transients will be too large. In order to minimize the effect of these transients, it is desirable to change the steam demand slowly instead of abruptly. The EHC system controls the rate at which steam demand is changed by controlling the opening and closing rate of the steam control valves. In other words, it controls the loading rate.

During turbine startup, steam is throttled to the turbine to bring it up to speed in a controlled manner. The EHC system senses turbine speed and acceleration, and positions the steam control valves to control speed and acceleration.

In summary, the three main purposes of the EHC electronics are to: control the load on the turbine, control the loading rate, and control the speed and acceleration during turbine startup.

The PWR EHC Mark II system electronics are made up of three basic units which accomplish these overall purposes. The speed control unit provides for speed and acceleration control. The load control unit provides for load and loading rate control. The flow control unit processes the speed control unit and load control unit signals and develops signals for positioning the steam control valves.

2.4.2 PWR Mark II Detailed Description

Figure 2-12 provides a functional block diagram of the speed control unit:

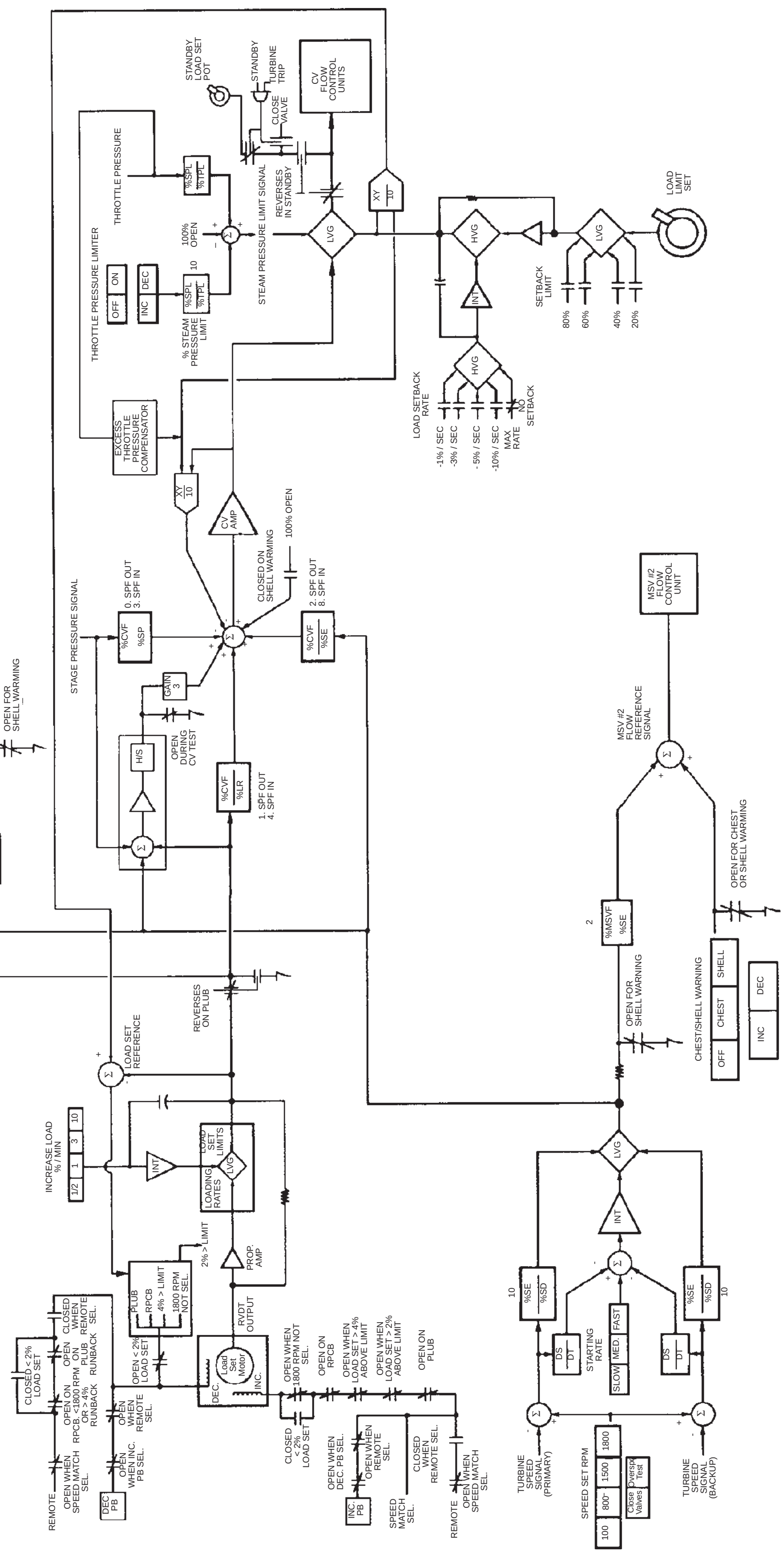

Figure 2-12
PWR EHC Mark II Functional Block Diagram

2.4.2.1 Speed Control Unit

The purpose of the speed control unit (SCU) is to develop a speed error signal used by the control valve (CV), intercept valve (IV), and main stop valve (MSV-2 amplifiers) to control turbine speed and acceleration. The speed input signals (primary and backup) are developed in the turbine front standard from two of the magnetic pickups that sense frequency from a toothed wheel on the turbine shaft. The turbine speed signal is subtracted from the speed reference signal at a summing junction to develop a speed error signal. The speed reference signal is set on the control panel where the following selections are available: 100 rpm; 800 rpm; 1,500 rpm; 1,800 rpm; Close Valves; and Overspeed Test.

After the summing junction, a gain of 10 is applied to the speed error signal before it is sent to a low value gate junction where the “most closed” valve signal is chosen and allowed to pass. Before the gain of 10 is applied to the speed error signal, it branches off to a differentiator. The differentiator outputs the rate of change of the input signal, thereby converting the speed error signal to an acceleration signal. This occurs for both the primary and backup speed error signals. After differentiation, the signals are then sent to a summing junction where each one makes up one-half of the acceleration signal. A third input to this summing junction is the acceleration reference, which is set at the control panel by the Starting Rate Selector. The available selections are: Slow, Medium, and Fast.

When the system is first energized, Slow is automatically selected. These selections correspond to acceleration rates of 60 rpm / min., 90 rpm / min., and 180 rpm / min., respectively. The acceleration signals are subtracted from the acceleration reference at a summing junction, resulting in an acceleration error signal. The acceleration error signal is sent to an integrator. The integrator performs the opposite function of a differentiator; it outputs a rate of change signal (ramp) proportional to the magnitude of the input signal. After integration, the acceleration error signal becomes a speed error signal and is sent to the low value gate. The output of the low value gate is the speed error signal, which calls for the most-closed valve position (or least open).

2.4.2.2 Load Control Unit

The purpose of the load control unit (LCU) is to develop CV and IV flow reference signals used by the flow control unit to control the load and loading rate. The LCU receives three signals used to compute a flow reference signal: Speed Error from the speed control unit, Setback and Runback signals from the reactor power cutback system, Limiting and Demand signals from the operator.

2.4.2.2.1 Loading Rates and Load Set Limiter

The purpose of the loading rates and load set limits (LR / LSL) portion of the EHC system is to develop the load reference signal.

The desired load signal is set at the control panel by the load selector INCREASE and DECREASE push buttons. (The buttons operate the load set motor, which positions a rotational variable differential transformer RVDT.) This outputs a linear signal from 0% to 100% load. The load set motor is geared to change load set at a rate of 130%/min. This signal then passes through a series of gates to be compared to the increase rate amp where the two signals compete for control. The load set motor can be increased or decreased using the load set push buttons on the EHC control panel. When speed matching is in use, the speed matching circuitry also increases or decreases load set. The following inhibits prevent the load set motor from being moved in the increase direction:

- Load set 2% above load limit
- Load set 4% above load limit
- Power/load unbalance condition
- Reactor power cutback in progress
- 1,800 rpm not selected at SCU (not applicable < 2% load set)

The Increase push button is also inhibited when the Decrease push button is selected and when remote operation is selected. The remote circuitry, in turn, is inhibited when speed matching is in use.

In addition to the inhibits above, certain conditions will cause the turbine load set to automatically be runback to a preset limit. These conditions are: power/load unbalance; reactor power cutback in progress; load set 4% above the load limit; and 1,800 rpm not selected at speed control unit.

All of these conditions are bypassed when the load set is below 2%. Load set will be reduced to a minimum of 60%, depending on the conditions and circumstances. Once the condition causing the setback has cleared, load set can be returned to 60% without resetting the load limit circuitry. To reset the load setback, reduce load limit until it just takes control of turbine loading. This will be noted by control valves currents dipping slightly. Then increase the load limit to its desired value. Load set may now be increased above 60%.

The Decrease push button is inhibited when the Increase push button limit switch is depressed and when remote operation is selected. Remote decrease operation is, in turn, inhibited when speed matching is in use or a setback condition with load set above 2% exists.

The loading rates are selected, by the operator, at the control panel. Push buttons on the control panel provide for loading rates of 1/2, 1, 3, and 10%/min. When synchronized with the grid, the loading rate is automatically set to 10%/min. When the operator initiates a load change, the appropriate rate amplifier comes out of saturation and outputs a ramp signal from the old load set value to the new load set value at the selected rate. Due to the low value and high value gate arrangement, the rate amp gains control until the new load set signal is reached. At that point, the load set signal recovers control, and the rate amp goes back into saturation. The load reference signal decreases along with the RVDT signal as long as the Decrease Load push button is pressed. The loading rate circuit is limiting in the “increase” direction only. The output from this section of the EHC system is called the load reference signal. The load reference signal is grounded (becomes 0%) on a power load unbalance (PLU).

The rate-sensitive PLU circuitry anticipates a turbine overspeed under load rejection conditions. It responds by closing the control valves and intercept valves. Two conditions must be met for valve actuation to occur: The difference between turbine power and generator load must be approximately 40% of rated load or greater, and the load must be lost at a rate equivalent to going from rated to zero in approximately 35 msec.

2.4.2.2.2 CV Amplifier with Stage Pressure Feedback and Throttle Pressure Compensation

The purpose of the CV amplifier section (CVA) is to develop a CV flow reference signal used by the flow control unit to properly position the CVs. The three major signals summed at this junction are the load reference signal, the speed error signal, and the stage pressure signal. A l00% open signal is also summed at this junction, but only when shell / rotor warming occurs.

The gain applied to these signals varies depending on whether stage pressure feedback (SPF) is in or out. There is a direct relationship between turbine first-stage pressure and the actual load on the turbine. SPF makes use of this relationship. The SPF signal may be used to improve the linearity of the turbine’s response to load changes. At some plants, SPF is used only during control valve testing. As the control valve under test is being closed, SPF will change the load set reference to open the other three control valves to maintain turbine output constant.

When SPF is out, the stage pressure signal has a gain of zero. That is, the stage pressure signal is not used; therefore, the EHC System does not respond to changes in stage pressure. Under these conditions, the load reference signal is summed with a gain of 1, and the speed error signal is summed with a gain of 2. Summing the speed error signal with a gain of 2, after a gain of 10 has already been applied in the SCU, results in a CV regulation of 5% with respect to speed error For example, if the turbine were to overspeed / underspeed by 5% of rated speed (0.05 x 1,800 rpm = 90 rpm), the CVs would receive a 100% close / open signal to compensate.

For SPF to be placed in service, stage pressure must be greater than 20% of rated and main steam throttle pressure must be greater than 95% of rated. When SPF is placed into service, two motor positioned ganged potentiometers will drive the gains. With SPF in automatic, the stage pressure signal has a gain of 3. In manual, the operator controls gain using the Increase / Decrease push buttons. This gain is subtracted from the load reference signal and the speed error signal, which now have a gain of 4 and 8, respectively. The net result of changing the speed error and load reference gains, when stage pressure feedback is in, is that the overall EHC system gain remains unchanged. The CVs now respond to changes in stage pressure.

The control valve test bias circuit continuously samples the stage pressure signal. When stage pressure feedback is being transferred in or out, the bias circuit provides a signal equal to the last sampled stage pressure signal. This provides a bumpless transfer.

The flow control unit diode function generator is accurate for rated throttle pressure only. Compensation is required for throttle pressure above full-load rated pressure. The throttle pressure compensator (TPC) provides a gain to the load reference signal, which compensates for the pressure change from no-load to full-load. The TPC is always in service; it cannot be switched out. A failure of the throttle pressure sensor will cause a no-load pressure signal to be seen by the TPC.

2.4.2.2.3 Throttle Pressure Limiter

The purpose of the throttle pressure limiter (TPL) is to send a limiting signal to the CVs on low throttle pressure. This function may be turned on or off to completely disable the TPL.

The low throttle pressure at which the CVs begin to close is set by the operator from 0% to l00% rated throttle pressure (985 psi). The signal from the RVDT is summed with a gain of 10, as is the throttle pressure signal. The gain of 10 determines the size of pressure decrease below the set limit needed to close the CVs fully. In this case, the gain of 10 causes a full-close signal to be sent to the CVs when pressure has decreased 10% below the set limit.

A 100% open signal is also summed at this junction to maintain a full-open signal to the LVG under circumstances when the throttle pressure is non-limiting. The output of the TPL is gated with the output from the CVA in an LVG configuration so that the most-closed signal is passed to the flow control unit.

When EHC control is shifted to the standby control unit, the control valve flow reference signal is transferred from the output of the throttle pressure limiter low value gate to the standby load set potentiometer. If a turbine trip should occur while in standby control, the standby load set potentiometer signal will be replaced by a Close Valves signal.

2.4.2.2.4 Load Limit and Load Setback

The purpose of the load limit and load set runback (LL/LSR) circuit is to send limiting signals to the CVs under the following circumstances: When a setback is initiated and when the load reference signal exceeds the load limit set.

Under normal circumstances, with no limiting conditions taking place, the output of the LL/LSR is identical to the output of the CV amplifier. In actuality, the LL/LSR signal is slightly higher by field adjustment, so that under normal circumstances, the CV amp is in control.

An LVG at the input of the LL/LSR, compares the load limit set, and load setback limits signals, allowing only the most limiting signal to pass to the summing junction and be added to a 100% open signal. The resultant signal is compared to the load setback decreasing rate amp through an HVG. The load setback rate amp only takes effect when a load setback occurs. Then, in conjunction with the load setback limits, it decreases the CV flow reference signal in a controlled way from 100% until the setback clears. The output of the LL/LSR is gated with the output of the TPL and the CV amp in an LVG so that the most-closed signal is sent to the flow control unit to control the CVs.

When a reactor power cutback initiates a turbine setback, the turbine reduces load at 10%/sec to at least 60%. The setback seals in electronically within the load limit circuitry and is cleared by first resetting the RPCB module. Then turn the load limit potentiometer CCW until the load limiter just takes control. This will be indicated by the control valve current dipping slightly. Once the setback is reset, the load limit potentiometer can be set to the desired load limit, and the load set can be increased above 60% using the increase push button.

2.4.2.2.5 Main Stop Valve-2 Amplifier

The purpose of the main stop valve amplifier (MSVA) is to develop a signal used by the flow control unit to position the MSV-2 internal bypass during chest/shell warming. The MSVA sums the warming rate RVDT output and the speed error signal. When chest/shell warming is off, both speed error and RVDT inputs are grounded, and the output is 0. During chest warming, the speed error signal is not needed because the CVs are fully shut; therefore, the speed error input is grounded. During shell/rotor warming, the possibility of the turbine rolling off the jack and speeding up is real. In this case, the speed error signal is used to shut the MSV-2 internal bypass. The output of the MSVA is the MSV flow reference signal, which is sent to the flow control unit.

2.4.2.2.6 Intercept Valve Amplifier

The purpose of the IV amplifier (IVA) is to develop a signal used by the Flow Control Unit to position the IVs. The IVA sums the speed error signal with a gain of 5 and the load reference signal with a gain of 2.5. This results in an IV regulation of 2%. That is, if an overspeed occurs at 100% load, the CVs shut in the first 5% of overspeed (90 rpm). The IVs shut in the next 2% of overspeed (36 rpm). Both the IVs and the CVs are shut by 107% overspeed.

A 100% open signal is sensed at the junction to maintain the IVs wide-open during normal conditions. When chest/shell warming occurs, a 100% closed signal is summed to cancel the 100% open signal and close the IVs. The output of the IVA is the IV flow reference signal, which is sent to the flow control unit.

When EHC control is shifted to the standby control unit, a 100% open signal is substituted for the output of the IV amplifier. If a turbine trip occurs while in standby control, a Close Valves signal bypasses the 100% open signal and shuts the IVs.

2.4.2.3 Standby Control Unit

The standby control unit provides capability for the operator to manually establish the control valve flow reference signal using the standby load set potentiometer. The standby control unit is enabled when the EHC system is placed in the standby mode. The standby control also provides a 100% open signal to the CIVs and the MSVs to open them in the standby mode. In the event of a turbine trip while in standby, a Close Valves signal is sent to all valves.

There are only two means of overspeed control when the standby control unit is in control: the backup overspeed trip is reduced to 105%; this becomes the primary means of speed control, and the normal overspeed trip at 110% becomes the backup speed control.

2.4.2.4 Flow Control Unit

The purpose of the flow control unit (FCU) is to use the CV, IV, and MSV-2 flow reference signals to develop signals for the turbine valves to placed them in their proper position. The FCU also provides a means for position feedback (LVDTs), position monitoring, and function generator compensation for non-linear flow characteristics of valves.

Important components of the valve operating assembly are: the servovalve “servo,” the linear variable differential transformer (LVDT), and the flow characteristics of the valves themselves. The purpose of the valve operating assembly is to position the valve stem and to provide position feedback.

The flow characteristics for a control valve is not linear. The non-linear characteristic represents steam flow vs. valve position. The important thing to note is that the graph is curved (non-linear). For example, if someone were trying to position this particular valve manually to achieve 50% steam flow through it and assumed that positioning the valve stem half-way would result in 50% steam flow, he might be wrong. The actual steam flow achieved might be 88%. To achieve 50% flow the valve might only need to be open 22%.

The flow reference signals to the FCU are linear. In order for these signals to compensate for the non-linear behavior of the valves, the inverse function is applied in the diode function generator (DFG). The DFG is built into the valve position control unit (VPCU). The DFGs alter the input signal and provide a stem lift signal to the valve, which results in the proper steam flow.

The servo “converts” the electrical signal into mechanical movement of the valve. As the signal to the servos are increased, the valve moves faster. A positive signal corresponds to the valve opening, and a negative signal to the valve closing. When the valve is at rest, the signal to the servo is 0. Driven by a mechanical linkage connected to the valve stem, an LVDT is excited with a 3 kHz signal. Due to the transformer action, it provides a modulated signal proportional to valve position. The LVDT signal is used for position feedback and for position monitoring.

2.4.2.4.1 Valve Position Control Unit

The purpose of the VPCU is to use the flow reference signal, the position feedback signal, and DFG compensation to develop a signal that opens or closes the servo-controlled valve as needed for system control.

2.4.2.4.2 Valve Position Driver

The purpose of the valve position driver (VPD) is threefold. The VPD accepts the open / close voltage signal from the VPCU and converts it to a current signal (+20 ma) to drive the servo valve. The VPD provides 3 kHz excitation for the LVDT. Also, the VPD demodulates the position signal from the LVDT and sends it to the VPCU.

2.4.2.5 Description of Integrated Operation

(See Figure 2-12 for a functional block diagram.)

This figure describes EHC system actions regarding major signal paths and functions. It is a simplified diagram, however, and does not describe all events and details. For example, the block diagram can be used to describe a typical turbine startup.

Initial Conditions:

- Reactor critical, normal operating temperature (NOT), normal operating pressure (NOP), low in the power range
- Turbine reset, vacuum drawn, shell warming required, on the jack
- Throttle pressure limiter—On, set at 100%
- Loading rate limit—10% / min. selected
- Load selector—0%
- Speed set—close valves
- Starting rate—Fast selected
- Chest / shell warming—Off
- Warming rate—0
- Load limit set—l00%

Given the above initial conditions, note that the IVs, CVs, and MSVs are shut. This happens because selecting Close Valves introduces a large negative value into the speed summing junctions. This causes the SCU to output a -100% signal. Inputting a -100% speed error signal into the CVA and IVA causes all the CVs and IVs to shut. Also, a contact closes when Close Valves is selected to command the MSVs shut. The ISVs open when the turbine is reset. The Chest / Shell Warming controls are used to slowly warm-up the turbine before loading to minimize thermal stresses. The warming rate must initially be decreased to 0 in order to change warming modes this is an electrical interlock. To begin warming, Shell is selected. When Shell is selected the ISVs close. The speed reference signal changes from -100% to 0%, and a 100% close signal is added to the IVA so that the IVs close.

The speed summing junctions sum the turbine speed with the 0% reference signal so that the speed error signal now becomes 0%. This is done to produce a speed error signal, which detects the turbine rolling off the jack during shell warming. The speed error signal is sent to the MSVs where a relay allows the signal to be used by the MSVs only during shell warming. The contact, which commanded the MSV-2 to shut with Close Valves selected, opens. The MSV-2 is now shut with the warming rate RVDT in control ready to open MSV-2 internal bypass.

In the CVA, a contact closes, inserting a l00% open signal during shell warming. This causes the CVs to open wide, permitting steam flow into the turbine shell. As the warming rate is increased, the internal bypass opens and the actual warming takes place. When shell warming is complete, the warming rate is decreased to 0, closing the bypass, and Off is selected.

When Off is selected, the system returns to Close Valves. In order to start the turbine, a speed is selected. Selecting 100 rpm, with a medium starting rate, causes the MSVs and the IVs to open. The speed set inserts a 100 rpm signal to the summing junction (about 5%). The turbine is initially at 0 rpm, so the output of the first summing junction of the SCU is +5%. This 5% signal now goes through three different paths to reach the LVG at the output of the SCU. The first two paths are those of the primary and backup speed error signals through the gain of 10 amplifier. These amplifiers multiply the 5% by 10 so that each one passes a 50% signal to the LVG. The gain of the backup signal is adjusted to be slightly higher, so the primary signal will always be chosen. The third signal path is through the acceleration amplifier which sees a 0 rpm signal from the turbine and a medium starting rate signal.

At the first instant 100 rpm is selected, the 50% open signal tries to pass from the LVG. The 50% open signal would result in much more steam flow than required to accelerate an unloaded turbine. The acceleration amp assumes control of the open signal and slowly ramps the speed error signal from the closed valves value to toward the open direction. The acceleration amp’s signal becomes the lowest and is passed through the LVG. As the turbine speeds up, the acceleration amp brings the CVs to the proper position to maintain a constant acceleration rate at its commanded value. As the turbine approaches 100 rpm, the speed error decreases to 0 and is eventually smaller than the acceleration signal. At this point, the primary speed signal gains control of the LVG and causes the turbine to remain at 100 rpm.

Selecting 1,800 rpm and a fast starting rate causes the turbine to accelerate to 1,800 rpm in the similar manner with the acceleration amp in control. With the turbine at 1,800 rpm, the generator is excited and voltage is raised 25 KV. The speed is matched and synchronized. One of the two parallel main circuit breakers is shut, and load is accepted by the operator with the Load Increase push button. The other main circuit breaker is shut, and the load is increased as desired. In this case, 10%/min. loading rate is selected. The Increase Load push button is then depressed until the load set is at the desired position of 100%.

The LR/LSL has a 100% load set signal into the LVG, and the increase rate amp increases its output from 0% to 100% at 10%/min. Initially, the increase rate signal is smaller, and it passes to the HVG. The HVG passes the increase rate signal. Thus, the load reference signal is ramping up at 10%/min. When the increase rate amp's output increases past 100%, the load set signal takes control through the LVG, and the CVs open enough to load the turbine to 100%.

2.5 Turbine Supervisory Instrumentation (TSI) Description

2.5.1 Brief Description

Figure 2-13 provides a block diagram of the TSI:

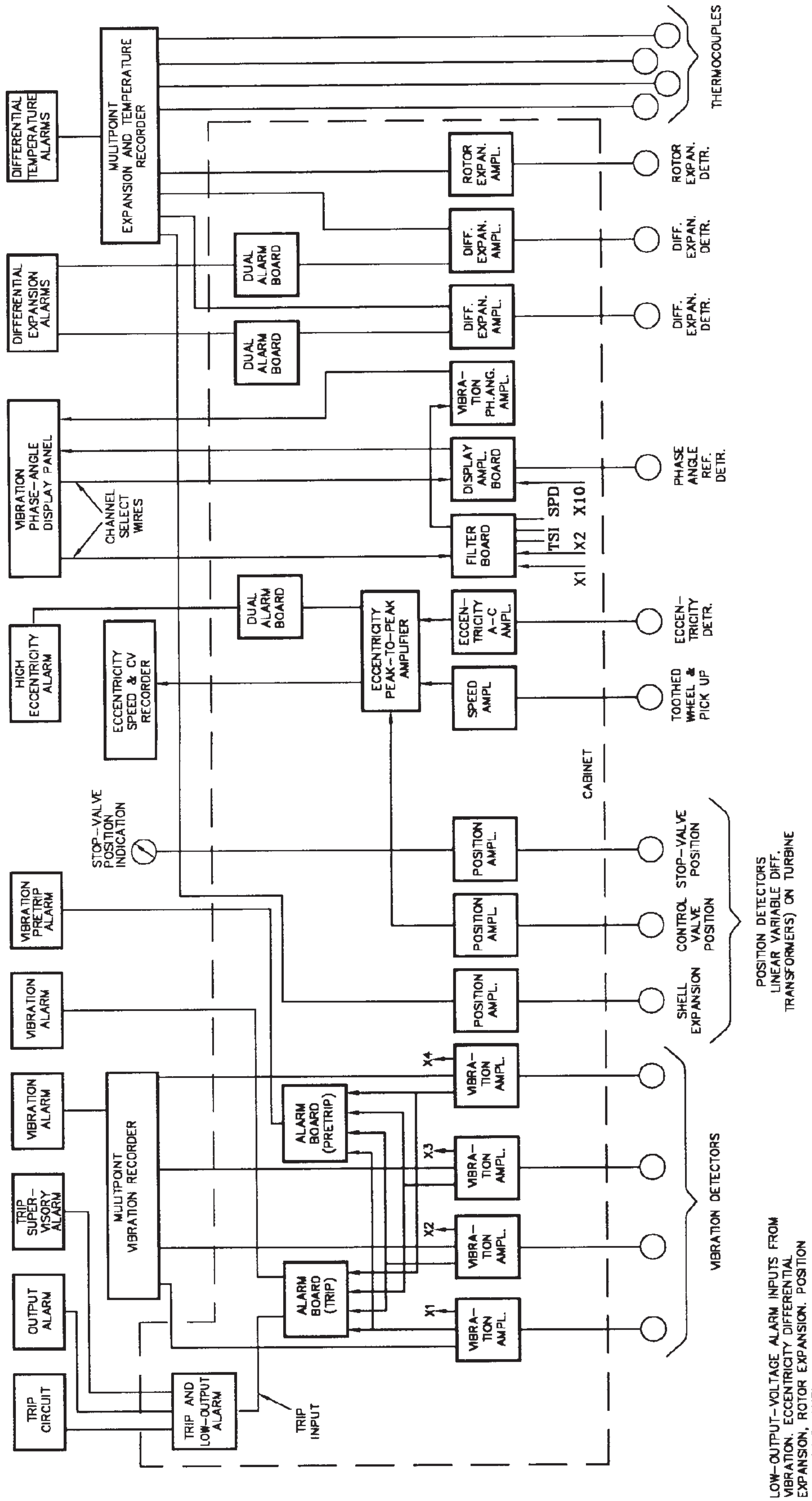

Figure 2-13
Turbine Supervisory Instrumentation Block Diagram

2.5.1.1 Measured Variables

The turbine supervisory instrument system is an instrumentation system for monitoring a number of variables on a steam turbine. Although the quantities that are measured vary with the turbine, they usually include some or all of the following:

- Vibration (number of channels depending on the turbine)
- Shell expansion (a position measurement)
- Total control valve position
- Speed
- Eccentricity
- Differential expansion
- Rotor expansion
- Shell temperatures
- Shell differential temperatures (number of channels depending on the turbine)

One or more of the following additional measurements might also be included in some systems:

1. Acceleration, stop valve position, bypass position, speed load changer position, stop valve position, intercept valve position, reheat stop valve position
2. Additional speed channels (for speed of feed-pump turbines)

2.5.2 Alarm and Trip

In most systems, dual-alarm boards are included for the vibration channels to actuate an annunciator, indicator lights, or other alarm device in case the vibration should exceed the preset limits. A trip board is usually included, connected in such a way that if any one or more vibration channels exceed their set-points, the trip contacts will be actuated. Some systems may be connected so the trip contacts will be actuated by excessive expansion, as well as vibration. The trip circuit is automatically disabled: if any of the vibration amplifier boards should be removed, if any of the vibration alarm boards is removed, if the trip board is removed, if the AC power should fail, or if either of the DC power supplies should fail. The tripping capability will be automatically restored about 45 seconds after the abnormal condition is restored to normal.

Dual-alarm boards are usually included for the differential expansion channels, and, optionally, one might be included for eccentricity.

2.5.3 Cabinet, Power Supplies, and Modules

The electronic equipment is housed in a cabinet. As shown in Figure 2-14, the cabinet includes (from top to bottom) two DC power supplies, an AC power supply, a test panel, and a number of modules that contain the printed circuit boards. The circuit boards plug into receptacles toward the back, inside the module. The number of modules used varies with different systems. However, the final assembly drawing (furnished with the GE system instructions) shows the number and type of modules used for the particular system.

2.5.4 Recorders

Vibration and eccentricity are generally recorded on a multi-point printing recorder. This recorder is usually equipped with adjustable back-set alarm switches, one alarm switch for each of the three chart sections.

Speed and control valve position are generally recorded on one-pen or a two-pen recorders. Some systems utilize one pen to record speed and a second pen to record valve position. More commonly, however, a single-pen recorder is employed. It is switched to record speed whenever the turbine-generator is not connected to the power-system lines and to record control valve position when the generator is on the line.

The recorder for shell expansion, differential expansion, and rotor expansion records in the left third of the chart, while the various temperature measurements are recorded in the right two-thirds of the chart. This recorder is sometimes equipped with adjustable back-set alarm switches, one high and one low alarm for each differential temperature channel.

Some turbine supervisory instrument systems might utilize other types of recorders than those discussed. In still other systems, some of the measurements may not be recorded but rather read on indicating instruments and / or a computer or data-logger.

2.5.5 Outputs Provided

Each of the measurement channels (except for acceleration) are provided with a 0.2 ma to 1.0 ma full-scale output suitable for operating a recorder, an 8 mv to 40 mv output for a computer and / or data-logger, and a 1 ma to 5 ma output for operating an indicating instrument. The acceleration channel is provided with a single output of -5 to 0 to +5 ma, center-scale, which is ordinarily used to operate an acceleration indicator.

3

REVIEW OF EVENTS

3.1 Description

A list of events, which contained references to the turbine/generator from 1985 through 1996, was extracted from industry databases (INPO, NPRDS, and OPEC). Additional event data was obtained from three BWR sites with Mark I EHC. Each site had two units. The additional event data had 21 events involving hydraulics and 32 involving other EHC subsystems. The events from the data sources were combined so they could be analyzed. There were a total of 570 events with a breakdown as follows:

- BWR plants with GE Mark I EHC—304 events (23 units in category)
- PWR plants with GE Mark I EHC—93 events (10 units in category)
- BWR plants with GE Mark II EHC—53 events (3 units in category)
- PWR plants with GE Mark II EHC—120 events (9 units in category)

3.2 Methodology

Each of the events was assigned to various items in each of five categories. The categories are:

- cause of event
- subsystem responsible for event
- effect of event on power generation capability
- mechanism behind event cause
- component involved in event

Note that not all of these categories apply to each event, and, for many of the event summaries, there was insufficient data to provide information in each category. The number of occurrences for each item was counted in an attempt to establish a pattern. The event frequency over time was also evaluated.

The events from the databases are contained in Appendix A for BWR units with Mark I EHC, Appendix B for PWR units with Mark I EHC, Appendix C for BWR units with Mark II EHC, and Appendix D for PWR units with Mark II EHC.

3.3 Event Trending Results

The event trends are displayed using several graphs. Each graph has three curves. The first curve is the average number of failures per unit that occurred in the year indicated on the x-axis. The second curve is a trend line that is derived from a least-squares fit of the first curve. The trend lines are labeled with a slope, which is the average change in failure rate over the period. They are also labeled with a "ratio" that is the failure rate at the end of the period divided by the failure rate at the beginning of the period. The third curve is the average cumulative number of events per unit at the end of the year listed on the x-axis.

3.3.1 Failure Rate Trend with Time

The frequency of occurrence of events for Mark I systems is shown in Figure 3-1; Mark II systems are shown in Figure 3-2. The most striking feature of these two figures is that the failure rate for Mark II systems shows a definite downward trend, while the failure rate for Mark I systems shows a definite upward trend. Since Mark I systems are somewhat older than Mark II systems, the Mark I systems could be showing signs of aging. (As of the end of 1996, the average age of Mark I systems is almost 20 years; the average age for Mark II systems is about 10.5 years.) It is important to note, however, that the actual failure rate for Mark II systems was greater than for Mark I systems until about 1993.

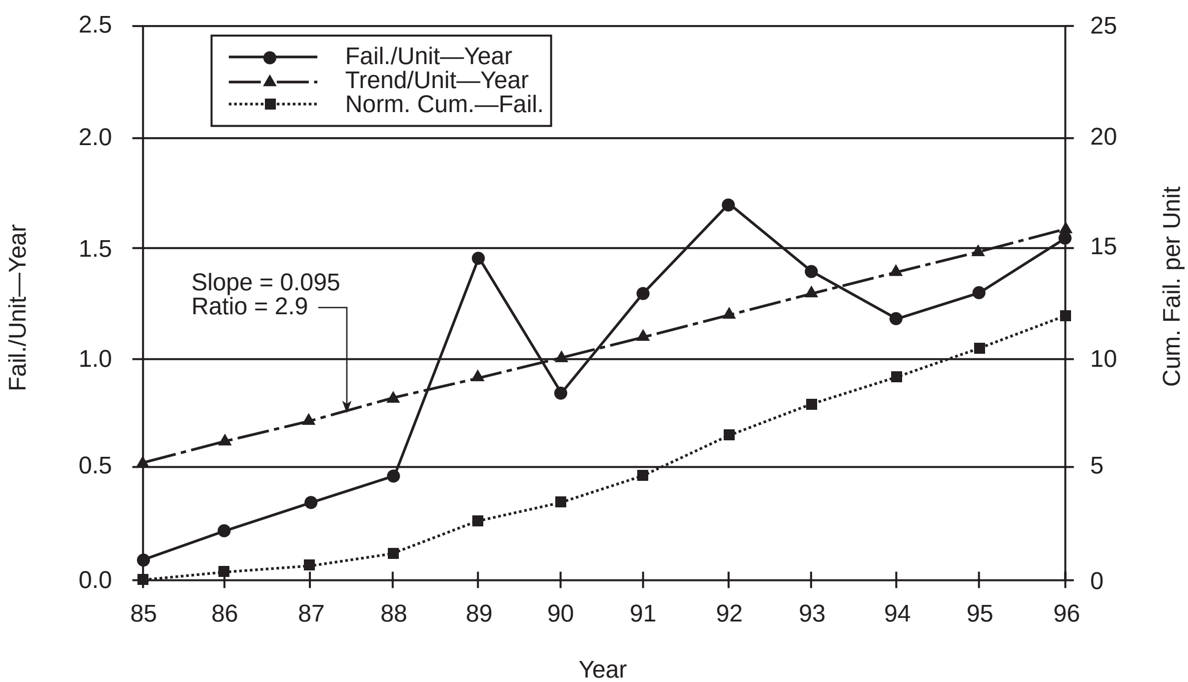

Figure 3-1
Event Frequency: BWR and PWR Mark I with Hydraulics and Test

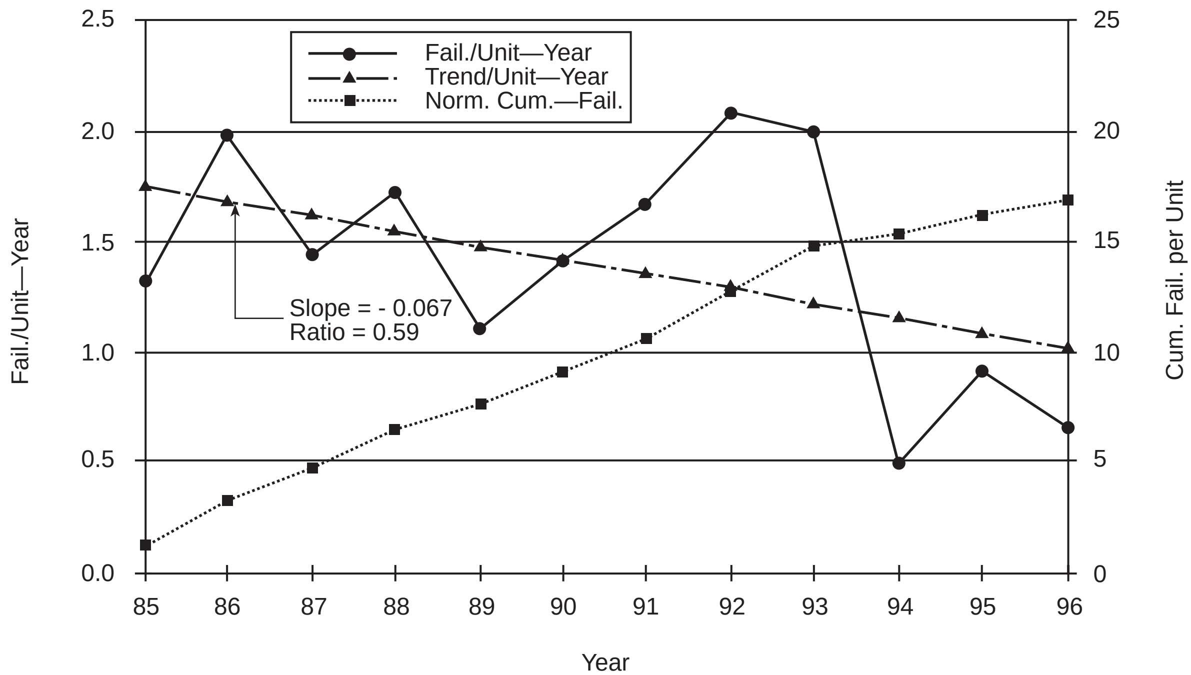

Figure 3-2
Event Frequency: BWR and PWR Mark II with Hydraulics and Test

Many of the events involve problems with the hydraulics, and the events include cases where plants have to reduce power in order to conduct turbine valve tests and other testing. In order to establish the failure rates for the electronics only, the rates without these items were determined. The results for Mark I systems are shown in Figure 3-3, and Figure 3-4 shows Mark II systems. With these items removed, the overall characteristic of the trend lines is the same, but the slopes are somewhat smaller.

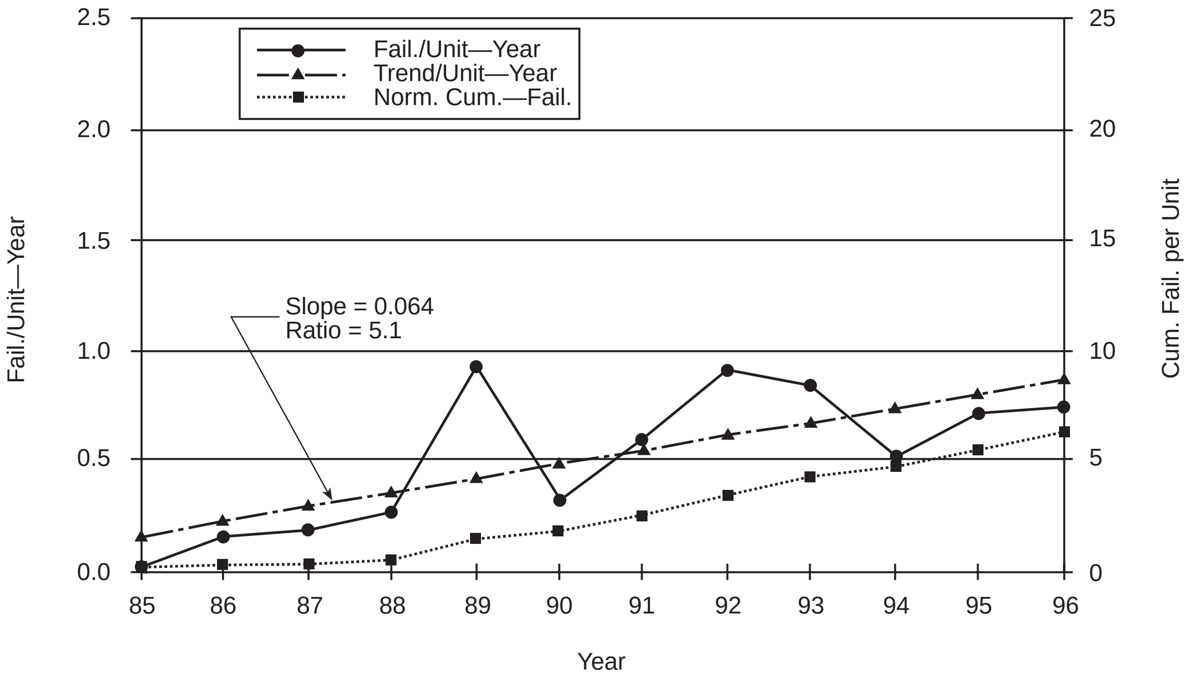

Figure 3-3
Event Frequency: PWR and BWR Mark I without Hydraulics and Test

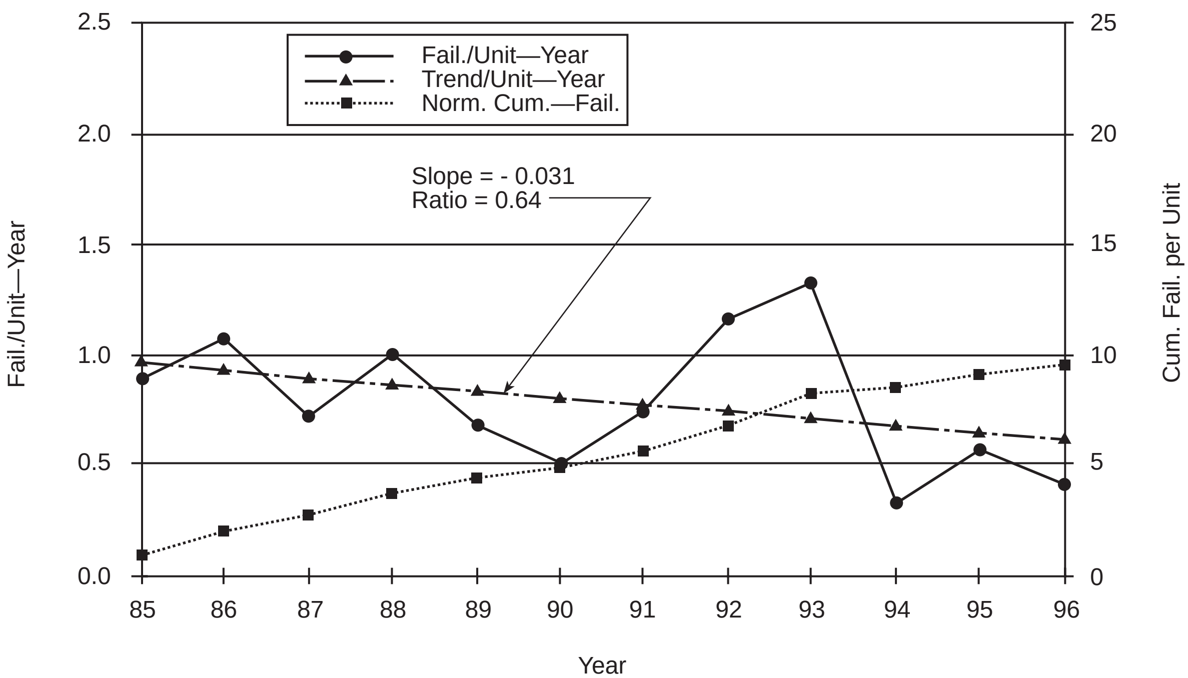

Figure 3-4
Event Frequency: PWR and BWR Mark II without Hydraulics and Test

The trends for BWRs with Mark I systems are shown in Figure 3-5. PWRs with Mark I systems appear in Figure 3-6. The trend lines for both show an increasing failure rate, but the slope for the PWR is significantly less than for the BWR.

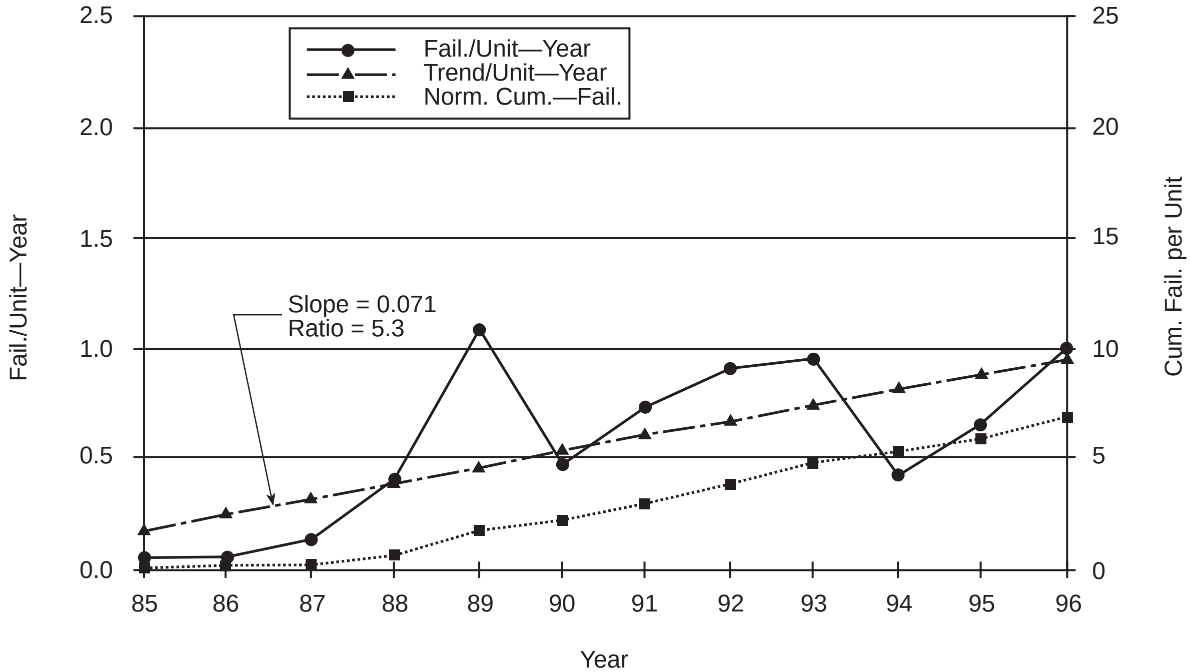

Figure 3-5
Event Frequency: BWR Mark I without Hydraulics and Test

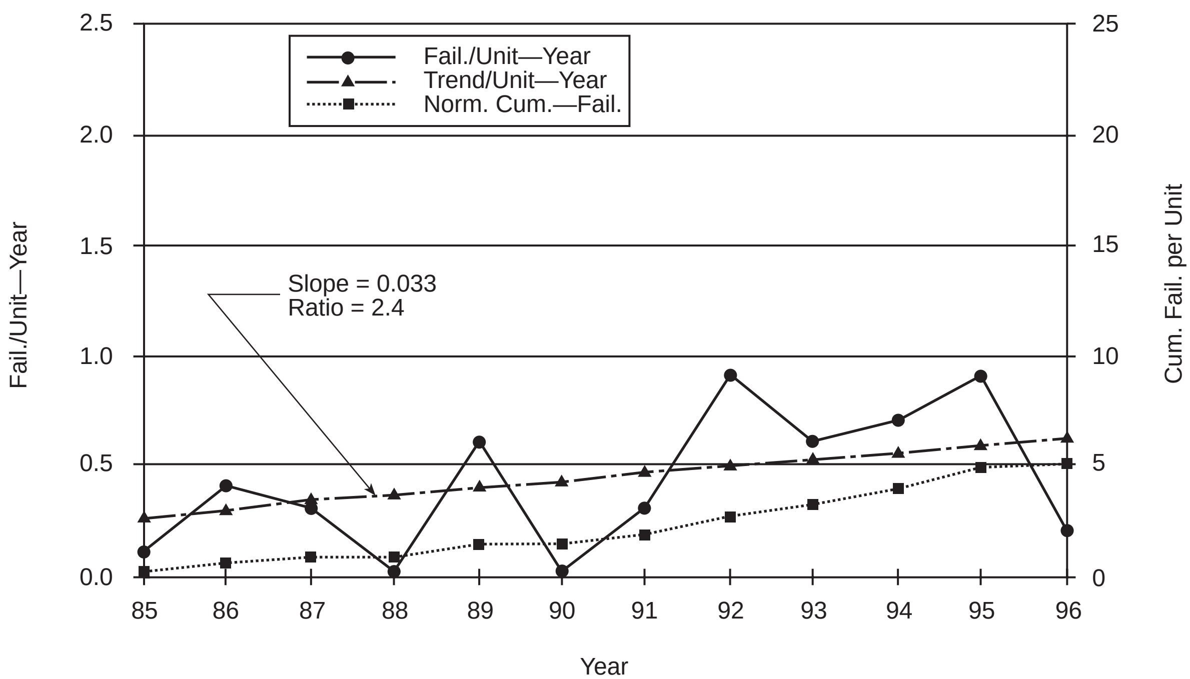

Figure 3-6
Event Frequency: PWR Mark I without Hydraulics and Test

The trends for BWRs with Mark II systems are shown in Figure 3-7; PWRs with Mark II systems are depicted in Figure 3-8. The PWR trend line shows a definite decreasing trend. The line for BWRs is almost flat. However, there are only three BWR Mark II units, so the trend is easily distorted. The bulge in failures in 1992 and 1993 is the result of several problems involving EHC during startups following refueling outages. If the relatively minor events in the 1992 to 1993 time frame are removed, then the trend becomes decreasing (see the Adjusted Trend line in Figure 3-7). Note that the slope of the cumulative failure line becomes flatter beyond 1993, which also indicates a decreasing failure rate trend.

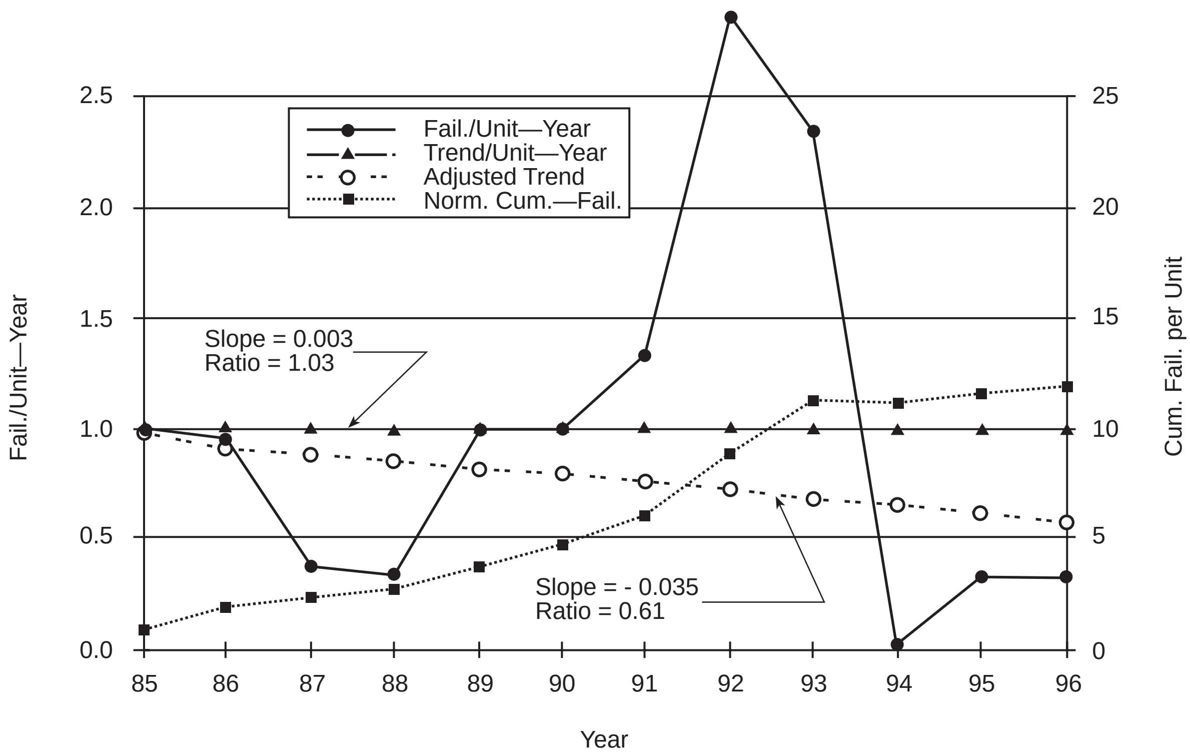

Figure 3-7
Event Frequency: BWR Mark II without Hydraulics and Test

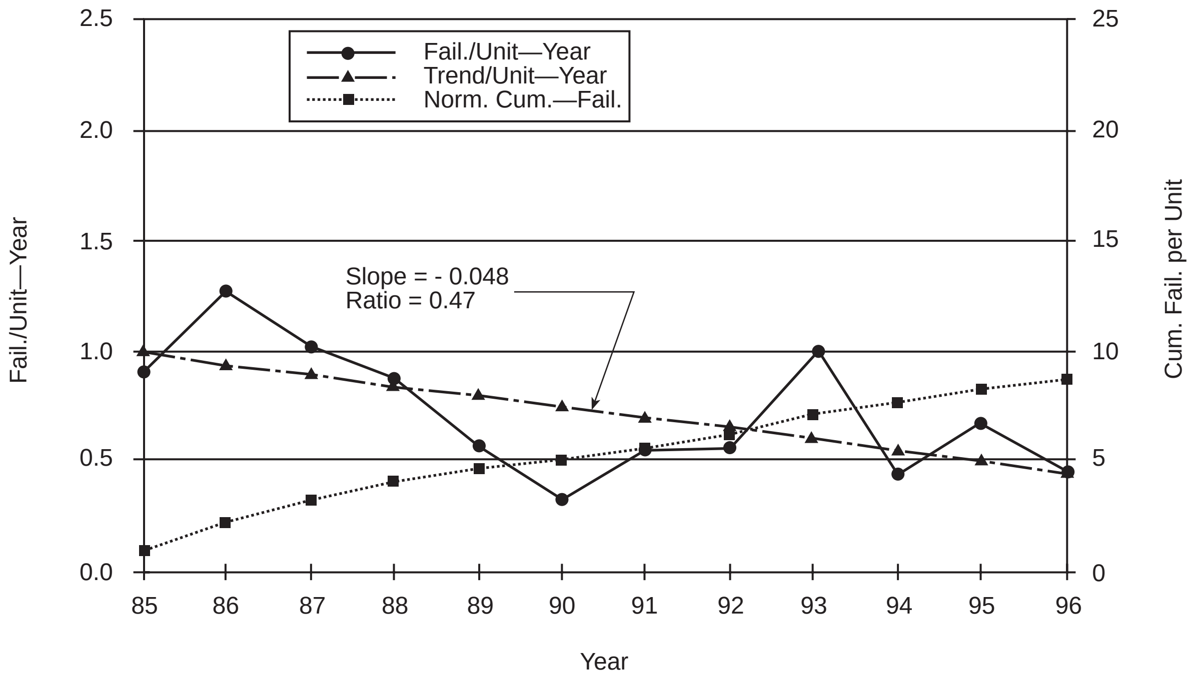

Figure 3-8
Event Frequency: PWR Mark II without Hydraulics and Test

3.3.2 Trend Evaluation

The trends are fairly well defined, except for the BWR Mark II with its small number of units. The increasing trends for the Mark I systems is a concern. Note that the additional data from the six units for the BWR Mark I systems is concentrated in 1994 and beyond. If the data is removed from the evaluations, the trend line for BWR Mark I systems becomes close to that of the PWRs (see Figure 3-9). This emphasizes the fact that the industry-wide databases do not show the complete spectrum of problems encountered in the EHC system. Given this effect, and the fact that the BWR EHC is more complex (the BWR includes the pressure regulator and bypass valve control loops in addition to the turbine controls; the turbine controls themselves also use additional gating circuits and the associated cards), the trends between the PWRs and BWRs do not appear to be significantly different.

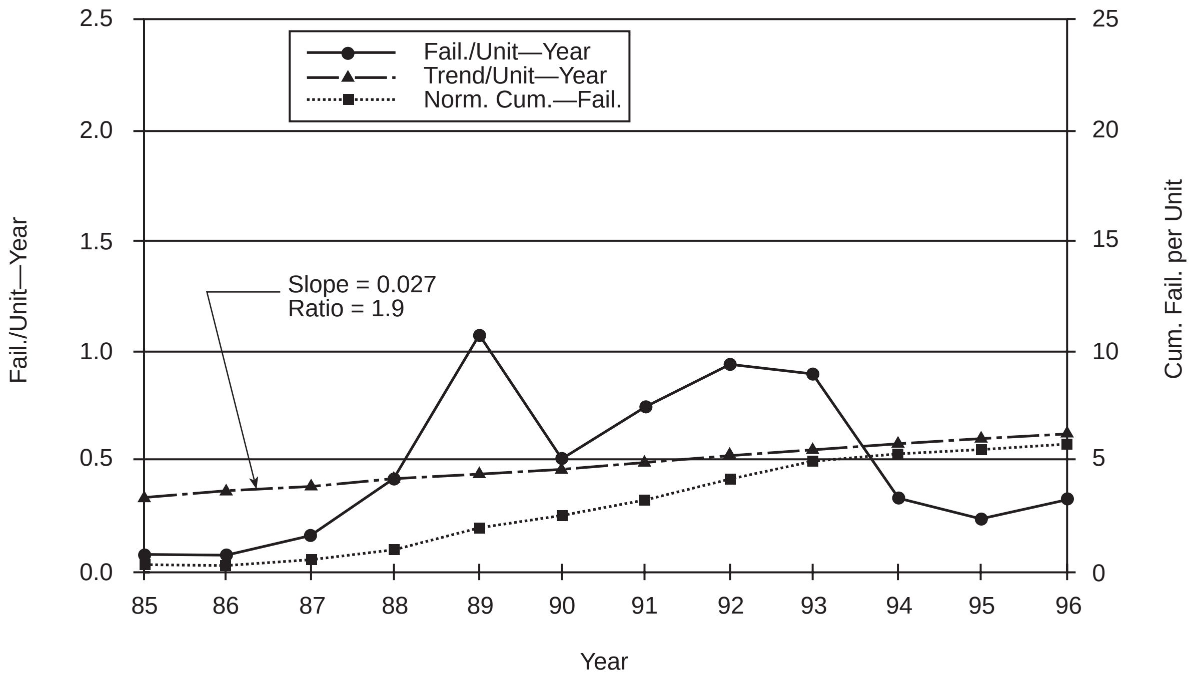

Figure 3-9
Event Frequency: BWR Mark I without Hydraulics and Test without Data from Plant Sources

3.4 Event Category Results

3.4.1 Cause Category

Each event was assigned a cause based on information in the descriptions. The basic causes range from someone running into a power pole, to lightning strikes, to turbine blades flying off, to normal failures. The number of events in each of the causes appear in Table 3-1. Hydraulics problems are included, and most of them are in the “leak” category. Also, note that some events involve more than one cause.

Table 3-1
Event Causes

Cause Distribution	PWR Mark II	BWR Mark II	Total Mark II	PWR Mark I	BWR Mark I	Total Mark I
Power Reductions for Testing	42	5	47	36	69	105
Failures	32	19	51	27	84	111
Leaks in Hydraulics	10	9	19	4	47	51
Procedure Errors*	7	4	11	6	38	44
Design Problems	2	7	9	2	19	21
Cause Not Given in Descriptions	13	5	18	3	26	29
Miscellaneous Causes	14	5	19	15	24	39
Total	120	54	174	93	307	400
Number of Units in Group**	7.3	2.6	9.9	10	20.5	30.5

* Includes problems with procedures themselves and failure to properly execute procedures.

** Represents average number of units for all of the years in the time frame used. Fractional values occur because units were operational for only part of one of the years.

A graph of each of the items is shown in Figure 3-10 for Mark II and Figure 3-11 for Mark I. The values in these figures are normalized to the number of units. For causes that are not exclusively hydraulics problems or test operations, the biggest cause is failures of some sort. Note that the number of failures for PWRs is somewhat less than for BWRs. This is consistent with the greater complexity of the BWR EHC. The dominance of failures and hydraulic leaks are a significant maintenance concern.

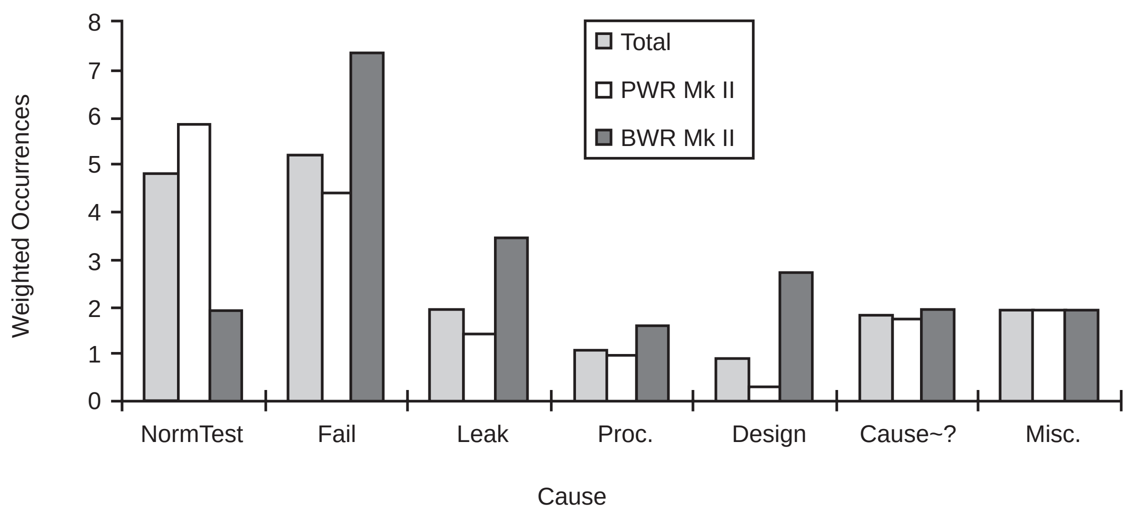

Figure 3-10
Causes of Events: Mark II

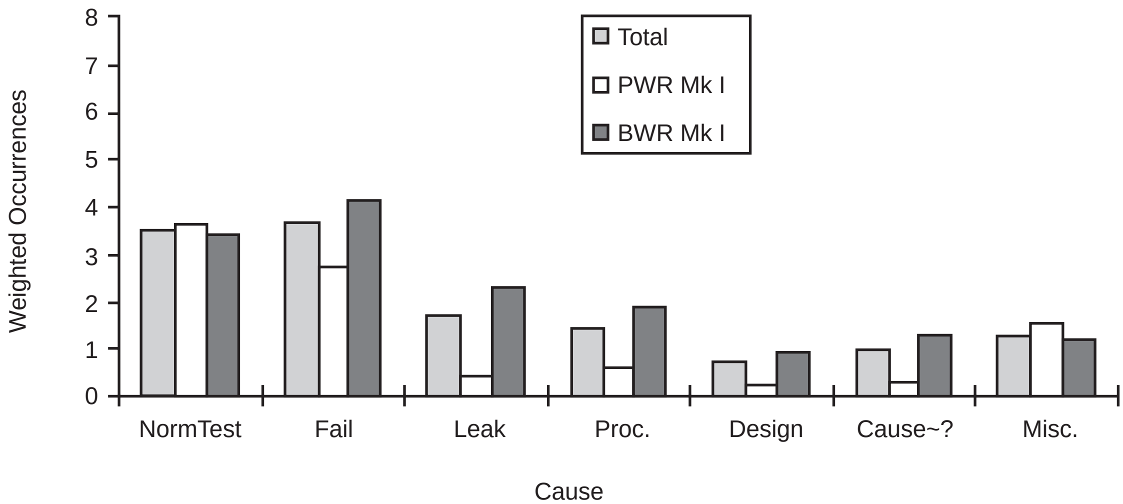

Figure 3-11
Causes of Events: Mark I

3.4.2 Subsystem Category

Each event was assigned a subsystem that was responsible for the event based on information in the descriptions. Table 3-2 lists the number of events in each of the subsystems.

Table 3-2
Event Causes per Subsystem

Event Distribution by Subsystem	PWR Mark II	BWR Mark II	Total Mark II	PWR Mark I	BWR Mark I	Total Mark I
Turbine System	81	20	101	74	148	222
Hydraulic Subsystem	14	16	30	6	77	83
Electrical Subsystem	13	0	13	6	11	17
Turbine Supervisory Instrumentation (TSI)	5	4	9	6	27	33
Generator Subsystem	3	6	9	1	6	7
Main Switch Gear	2	3	5	0	7	7
Subsystem Not Given in Description	2	0	2	0	4	4
SB&PR Systems	0	4	4	0	19	19
Man-Machine Interface (MMI)	0	0	0	0	5	5
Totals	120	53	173	93	304	397
Number of Units in Group	7.3	2.6	9.9	10	20.5	30.5

A graph of each of the items is shown in Figure 3-12 for Mark II and Figure 3-13 for Mark I. The values in these figures are normalized to the number of units. The largest number is in the turbine subsystem, which would be expected. The larger number of hydraulic problems in BWRs is consistent with the more complicated BWR hydraulics because of the bypass valves. Note that, for BWR Mark II systems, the bypass valves typically have a completely separate hydraulic system. It is important to note that the number of problems in the TSI and MMI are probably underrepresented in the industry databases because many of the problems in these subsystems would not create the type of events that are reported.

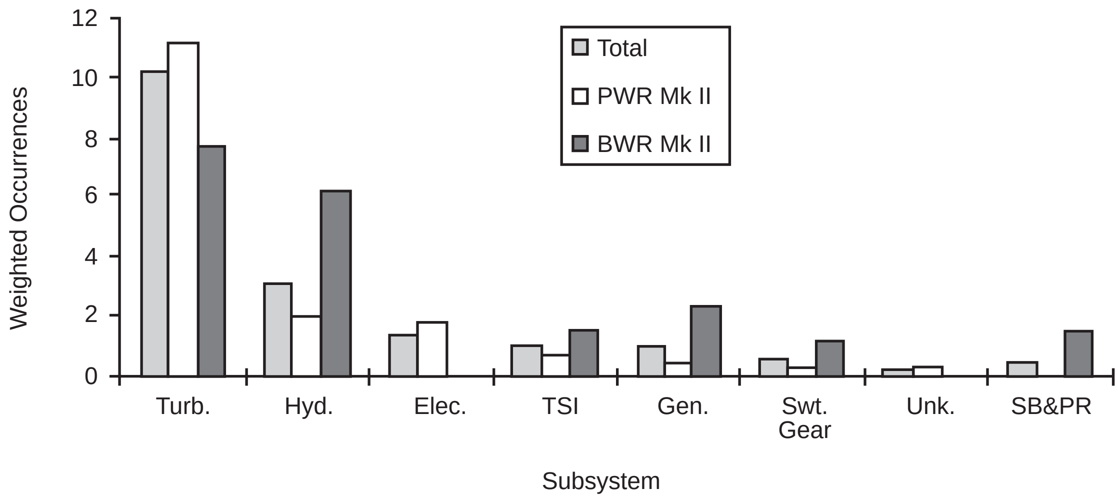

Figure 3-12
Event Occurrences by Subsystem: Mark II

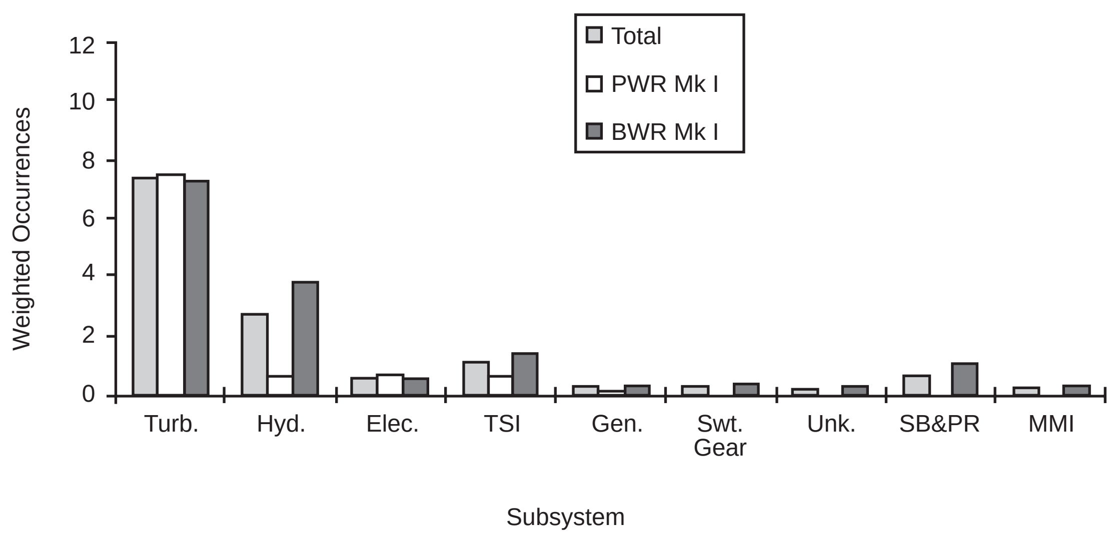

Figure 3-13
Event Occurrences by Subsystem: Mark I

3.4.3 Power Generation Effect Category

The effect of each event on power generation was assigned to an item based on information in the descriptions. The number of events in each category is shown in Table 3-3.

Table 3-3
Event Effect on Power Generation

Power Generation Distribution	PWR Mark II	BWR Mark II	Total Mark II	PWR Mark I	BWR Mark I	Total Mark I
Forced Outages	45	23	68	31	124	155
Planned for Testing	42	5	47	36	69	105
Load Reductions	14	1	15	7	39	46
No Effect	13	14	27	12	51	63
Occurred during Shutdown	6	10	16	7	21	28
Totals	120	53	173	93	304	397
Number of Units in Group	7.3	2.6	9.9	10	20.5	30.5

A graph of each of the items is shown in Figure 3-14 for Mark II and Figure 3-15 for Mark I. The largest number of events that are reported, other than planned power reductions for normal testing, are for forced outages. This is basically consistent with the fact that the industry databases are biased toward events that cause plant shutdowns. The cases with no effect and those that occur during shutdown are undoubtedly underrepresented.

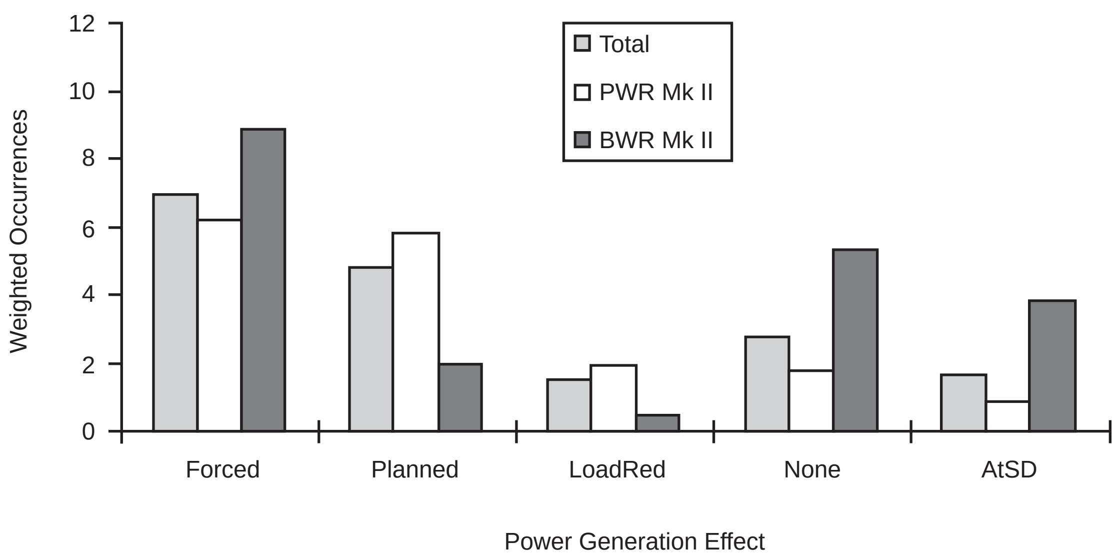

Figure 3-14
Event Occurrences by Effect on Power Generation: Mark II

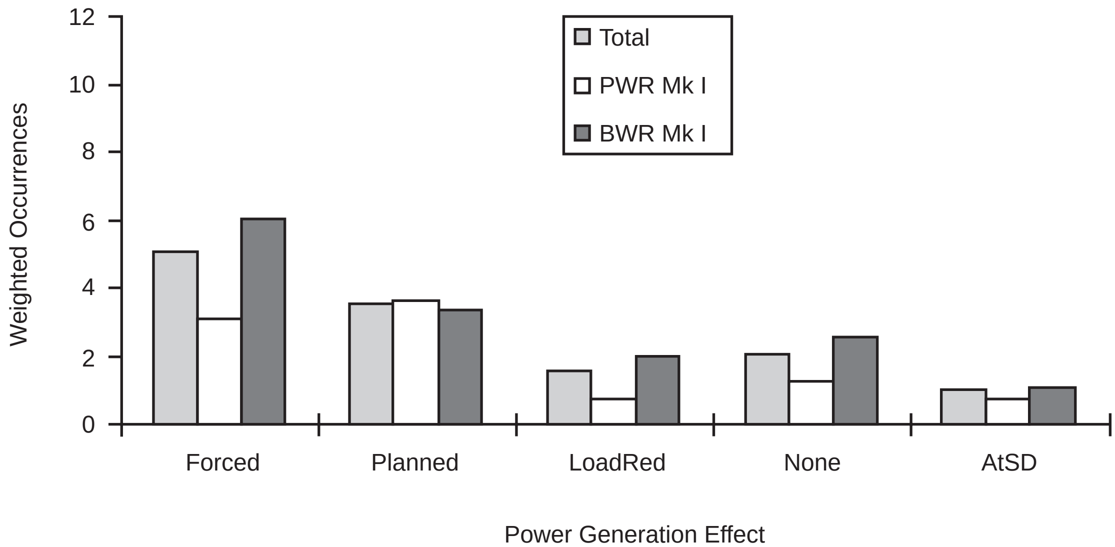

Figure 3-15
Event Occurrences by Effect on Power Generation: Mark I

3.4.4 Mechanism Category

The items in this category are dominated by "unknown" (132 for Mark I, 52 for Mark II) and cases where the mechanism is implicit in the cause (161 for Mark I, 94 for Mark II). Of the remaining events, the mechanism is scattered among a variety of items, such as wearout, high resistance, loose connections, and fatigue. The mechanisms for Mark I and Mark II are combined in Table 3-4.

Table 3-4
Event Cause by Mechanism

Item	Qty	Item	Qty	Item	Qty	Item	Qty
Air	4	Relay Bounce	1	Component	1	Coil Open	1
Corrosion	2	Defect	3	Early Life	1	Fatigue	17
Grounds	7	High Resistance	3	Instrument Line Non-Condensables	1	Installation	8
Intermittent	4	Lubricant	2	Mechanism Not Applicable	255	Mechanism Unknown	184
Multiple Mechanisms	1	Open Coil	5	Human Error	20	Plugging	1
Short	5	Bad Solder	1	Specification Error	2	Surge	1
Temperature	2	Water	4	Wearout	36		

3.4.5 Component Category

The items in this category do not contain a single dominating component or group of components. Note that, for a large number of the events (36%), a component is not involved. For example, test operations and procedure errors do not involve a specific component. No other identifiable component is responsible for more that 7% of the total. Even if all of the different electronic cards are included as a single item (45 cases), it would still be less than 8% of the total. Furthermore, 13% of the total did not identify a specific component. The components for Mark I and Mark II are demonstrated in Table 3-5.

Table 3-5
Event Causes by Component

Item	Qty	%	Item	Qty	%	Item	Qty	%	Item	Qty	%
Alarm Card	1	0.2	Amplifier Card	2	0.3	Turbine Blades	1	0.2	Breaker	1	0.2
Unspecified Card	7	1.2	Component Not Applicable	209	36	Connection	10	1.7	Contactor	1	0.2
Hydraulic Cooler	2	0.3	CV Amplifier	2	0.3	Exciter	2	0.3	Fan	2	0.3
Filter	13	2.3	Fitting	5	0.9	Fluid	4	0.7	Fuse	1	0.2
F/V Card	4	0.7	Indicator	3	0.5	Inverter	2	0.3	Load Limit Card	1	0.2
Lightning Arrestor	1	0.2	Limit Switch	11	1.9	Load Rate Motor	1	0.2	Load Rate Motor Gear	2	0.3
LVDT	1	0.2	LVG Card	2	0.3	Max. Comb. Flow Limiter	2	0.3	Main Gen. Instrument	2	0.3
Motor	1	0.2	Main Power Transformer	2	0.3	Main Steam Press. Sensor	6	1	Moisture Sep. Reheat	2	0.3
Multiple Components	1	0.2	O-ring	15	2.6	Pipe	12	2.1	PLU Card	2	0.3
PLU Sensor	1	0.2	Valve Positioner	3	0.5	Potentio-meter	6	1	Press Amp.	1	0.2
Pressure Switch	7	1.2	Probe	1	0.2	Pump	2	0.3	Power Supply	15	2.6
Component Unknown	77	13	Recorder	1	0.2	Reference Card	3	0.5	Relay	36	6.3
SADI	3	0.5	Seal	7	1.2	Servo	3	0.5	Solenoid	17	3
Speed Controller	1	0.2	Strainer	1	0.2	Switch	4	0.7	TBWD	9	1.6
Temperature Switch	2	0.3	Throttle Pressure Limiter	1	0.2	Trip Latch	1	0.2	Turbine Vibration	4	0.7
Valve	12	2.1	Volt Comparator Card	4	0.7	Volt Switch	2	0.3	VP Card	5	0.9
Weld	4	0.7	Wobbulator Card	1	0.2	Transformer	2	0.3	Extraction Line	1	0.2
Load Dec. Card	1	0.2									

3.5 Event Evaluation

The units in the database represent nearly 500 reactor years of operation. Of the events, 223 (39%) resulted in forced outages. This is roughly one forced outage every two reactor years. An evaluation of only the events that lead to forced outages gives similar overall trends (see Figures 3-16 and 3-17), except that the magnitudes of the trend slopes are smaller, as would be expected. The number of components involved are fewer but still distributed over a large number of components with a slightly larger contribution from relays (11%) and a larger fraction that involved procedural errors (18%). Note, however, that a procedural error has occurred on the average of only once every 10 unit years.

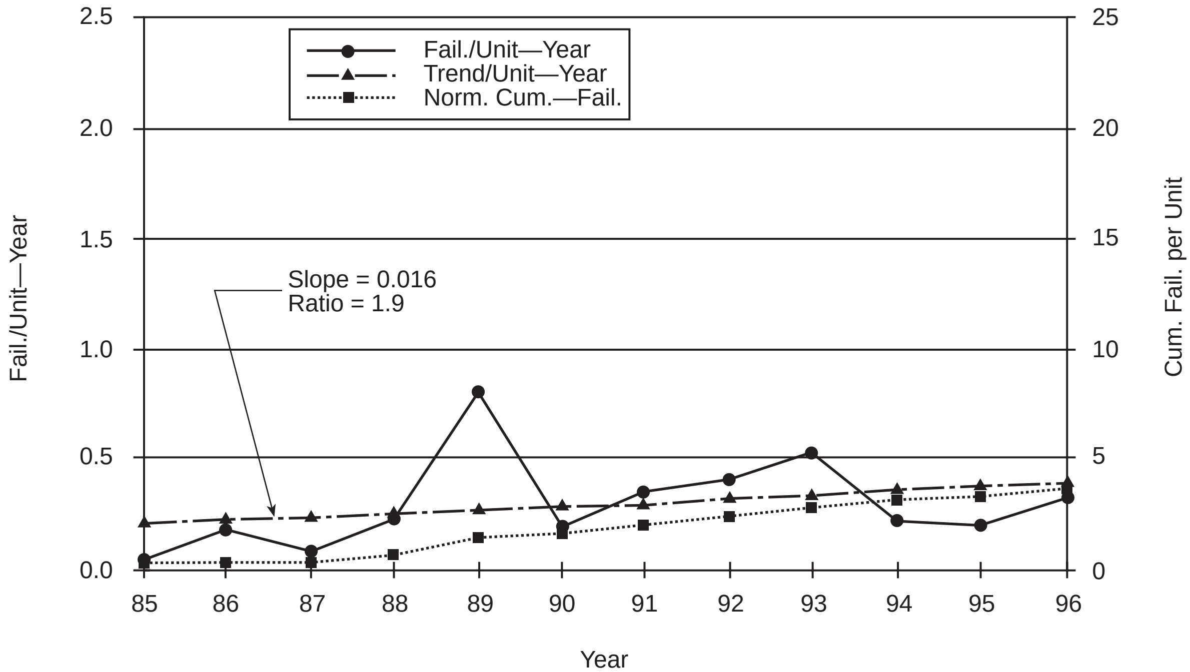

Figure 3-16
Forced Outage Event Frequency: BWR and PWR Mark I without Hydraulic and Test

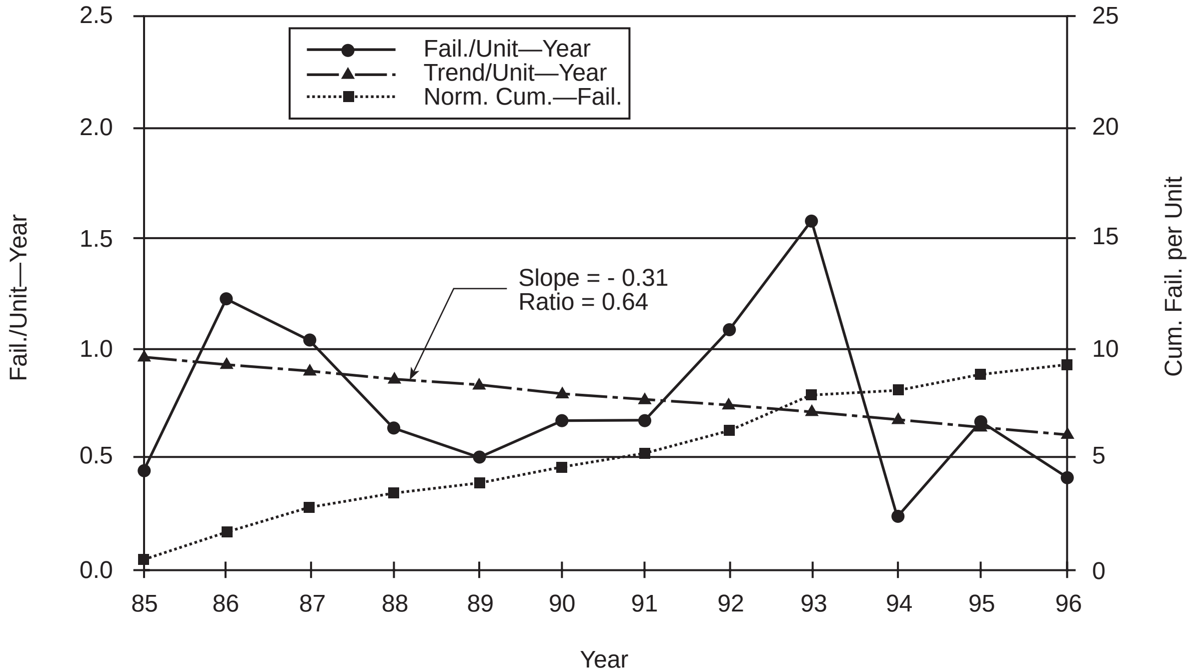

Figure 3-17
Forced Outage Event Frequency: BWR and PWR Mark II without Hydraulic and Test

If the event trends for Mark I systems continue, then the frequencies of events and forced outage could continue to increase. Component failures, combined with hydraulic leaks (which are a type of failure), account for over one-half of the events. These types of problems can be addressed with suitable maintenance and troubleshooting procedures. The processes used must encompass a broad range of device types because the problems are not concentrated in a particular class of components. The problems are similar for both BWRs and PWRs, except that the BWRs have the additional problem of containing circuits that are unique to BWRs. The Mark II systems exhibit a decreasing trend at this time. However, the average age of the Mark II systems is approaching the age at which the Mark I system began to show an increasing trend.

4

REVIEW OF SURVEYS

4.1 Summary

The fleet of plants that use the GE Mark I and Mark II EHC was solicited to fill out a survey regarding EHC electronics maintenance. The responses to the survey represent 36 plants, with a reasonable sample of each of the four plant categories. The responses were collated and tabulated to establish the spectrum of maintenance practices. The collation of the responses is contained in Appendix E. See this appendix for additional information on the following evaluations—in particular, the comments made by various respondents for each of the questionnaire items. There are a few common maintenance practices and a fairly broad variation in others.

4.2 Survey Evaluation

The responses to the items in the survey are summarized and evaluated in this section. Sixty-five percent of the respondents chose to add general comments at the end of the survey. It is worth noting that most of these (45% of respondents) felt that the GE EHC system was reliable. (One respondent felt fortunate the plant did not use the Mark V system, which was causing problems at a gas turbine facility.) However, a few also described some rather irritating and persistent problems, and several expressed concern about long-term support of the system.

There were cases where more than one individual from a site responded to the questionnaire. There were some minor inconsistencies in these cases. However, the inconsistencies can be attributable to the difference in perspective of the respondents. The event collation represents a combination of the multiple responses. The inconsistencies highlight the fact that any utility reviewing its maintenance program needs to ensure that the review is broad based and adequately addresses all phases of maintenance.

4.2.1 Plant Status Items

The first item in this category was a poll to find out what modifications had been installed at the plants. The utilization of a particular modification varied from none of the respondents having installed it to three-quarters of the respondents using it (if it applied to their plant). Several respondents also listed various modifications that had been made or were being planned. The importance of this is that there are significant differences between the systems in the "fleet." Care must be used to ensure that any items are carefully evaluated for applicability to a particular plant. Basically, though, they are all still GE Mark I or Mark II systems and share common elements, features, and problems. Few of the modifications were installed by more than half of the respondents. Generally, one-quarter to one-third of the respondents installed a particular modification, and one had not been installed by any of them.

Thirty-six percent of the respondents had an A1 maintenance rule classification for their plants, but it did not appear to have a major impact on plant operations for any of them. Forty-five percent of the respondents had implemented a power uprate. Fifty percent of the respondents listed hydraulics as the biggest cause of problems, while only twenty-five percent listed the electronics as the biggest cause.

4.2.2 Maintenance Practices Items

These items are intended to establish an overview of the performance of maintenance at the facilities. The results for these items are:

1. Eighty-five percent of the facilities had the maintenance performed by a small group of technicians who were familiar with the system. A small fraction used primarily GE for their maintenance.
2. Seventy-five percent of the plants did a complete line up every fuel cycle. The remaining plants performed the maintenance on a three fuel cycle basis, but most of these did a significant portion of the lineup every cycle.
3. Sixty percent did some form of on-line maintenance, but this was generally limited to changing oil filters and fixing problems that could reasonably be performed on-line.
4. Sixty percent used few maintenance procedures, while 30% used many procedures. The remaining plants used a mix of procedures (for example, few for the electronics; many for the hydraulics) or followed and other the GE line up instructions almost exclusively. Sixty percent used stand-alone procedures, while 35% used procedures that reference the vendor manuals to varying degrees. The remainder used a mix of stand-alone procedures and those that referred to the vendor manuals.
5. Seventy-five percent of the respondents performed some type of bench testing of new modules prior to installing them. The extent of testing ranged from basic DC operation to complete testing. Some did it only for specific devices, but none relied entirely on bench testing. After installation, testing was the primary method for assuring operability.
6. Fifty-five percent discarded replaced items, and 35% did some rework of their boards. This breakdown is a little misleading because, in some cases, the removed cards were sent out for rework. Of those who indicated the boards were reworked, there was nearly an even split between on-site and off-site rework (GE, third party, or corporate repair center). Thirty-five percent did periodic refurbishment of some

items. One respondent indicated an interest in setting up a more rigorous PM program. As expected, the most common item was the power supplies, but other items were mentioned.

7. Seventy percent of the respondents gave some description of the process used to determine if a component should be replaced based on behavior during routine maintenance. Of those, 70% were in the “reasonable doubt” category. This typically means that the component is replaced if the technician finds that it is difficult to calibrate or exhibits some other atypical behavior. The other respondents are in the “high doubt” category, in that a defined behavior (such as being unable to calibrate it to specification) is used to reject an item.

8. Twenty percent indicated that a root cause analysis was always performed. Five percent indicated that a root cause analysis was never performed. The rest sometimes performed a root cause analysis. Of those that performed a root cause analysis, 35% did it on-site. The remaining are spread out between GE, third party, site with assistance from GE or a third party, and corporate organizations.

9. Forty-five percent of the facilities did some on-line data collection to assist with maintenance. The collected data was used for specific purposes. For a few of the respondents, the on-line data was taken only to address a specific problem on a case-by-case basis. Eighty-five percent had some type of maintenance database. Of these, 30% used the data for some type of trending purpose. Usually, the trending is for a specific purpose, such as power supply monitoring or hydraulic fluid monitoring. However, one respondent indicated that the “as-found” and “as-left” data for control circuits was useful for troubleshooting.

4.2.3 Operating Experiences and Practices

These survey questions were intended to gather information on how well the system operates and how its operation effects or could effect maintenance practices. The results are as follows:

1. For the listed tests, the frequency of performance varied dramatically. For all of the tests, except pressure regulator fail over, at least 10% of the respondents had a weekly test interval. For other plants, the same test had up to a one refuel cycle interval, while some BWRs did not have bypass valve (BPV) testing. In all cases, the longest test interval was at least quarterly. The need for a specific interval will depend on the details, characteristics, and operating history of a specific plant (for example, plants classified as A1 under the maintenance rule could have shorter test intervals), but the degree of spread is surprising. The test interval is a maintenance-related issue and can be a wearout-related issue. **Plants with short test intervals should reexamine the basis for the intervals and extend them, if reasonable**.

2. One hundred percent of the plants in the survey had one or more EHC-caused forced outages since 1989. (Data from the events section was used for these numbers, not the survey results.) The number goes from 1.5 outages per plant to 7 outages per plant over the time span. The plants also had capacity factor losses in addition to

forced outages. The capacity factor losses were power reductions for the performance of turbine valve tests, power reductions for repair, and extended unscheduled outages for troubleshooting.

3. Forty-five percent indicated that the EHC caused some operational difficulties. The most common was during plant startup (72% of those indicated a problem, which was 40% of the total). The second most common was testing (36% of those indicated a problem, which was 20% of the total; most were for plants that had to reduce power to perform turbine valve testing). For the other conditions (plant shutdown and plant power maneuvering), only 10% of the respondents indicated that this was a problem.
4. One-third of the plants with standby turbine control indicated that it was used on infrequent occasions to support maintenance operations. Of the plants with a throttle pressure limiter: 18% used it all or most of the time, and the remainder never used it. Of the plants with a load limit: 45% used it all or most of the time, 8% used it only during valve testing, and the remainder did not use it at all. Of the plants with stage pressure feedback: 36% used it only during valve testing, and the remainder did not use it. Of the plants with a maximum combined flow limiter, only 5% of the respondents with BWRs used it.
5. Twenty-seven percent indicated major problems with the procedures used for EHC operation and testing. With regard to problems during normal plant operation, 40% indicated there were problems. The problems were with the valve position meters, the motor-driven pots, light bulbs, switches and indicators, panel connectors, and the awkward location of some front standard test switches.
6. Sixty percent of the respondents indicated problems caused by sensitivity to temperature changes. Twenty-three percent indicated that electronic noise was a problem. None indicated that there were vibration- or humidity-related electronics problems. Several respondents indicated that no radios were permitted near the EHC electronics.
7. Twenty-five percent indicated that there had been an abnormal response to operator actions. The responses include: relay races that came out wrong, noise and other problems with the pressure set points, and spurious bypass opening when manipulating the pressure set point.

4.2.4 Maintenance and Troubleshooting Experience

These items were intended to gather information on experiences with the maintenance and troubleshooting process. The results are:

1. Seventy-five percent of the respondents indicated that there were characteristics of the system that complicated maintenance. The most common problem given was that some calibration adjustments were difficult to complete (55%). The second largest factors were difficulty in establishing plant conditions needed to perform calibration (25%) and replacing some of the modules was particularly difficult (25%). The remaining factors were considered a problem by 10% or less.

2. Sixty percent of the respondents indicated that there were high-maintenance items. The items listed covered a broad range of devices, and there was no dominant device. The main causes were drift (23%) and failures (23%).
3. Forty percent indicated that aging appeared to be a problem. The devices that were listed as showing signs of aging were quite varied, and there again was no dominant device. Thirty percent indicated that they had observed problems with new devices failing. The devices listed were also varied.
4. Seventy percent indicated that there were problems with the maintenance procedures. The dominate complaint was inadequate system documentation (50%). The other reasons identified were:
    - Procedures are inflexible (14%)
    - Data recording is inadequate (23%)
    - Procedures are complex (14%)
    - Procedures are incorrect (36%)
    - Miscellaneous (10%)
5. Eighty percent gave some indication of the amount or frequency of training. There was a broad spectrum of training policies. The intervals ranged from two years to five years, and the training ranged from training based on system documentation only, to apprenticeship only, to training by outside vendors, to combinations of classroom training and apprenticeship. Sixty-eight percent indicated that keeping maintenance training current was a problem. Those sites with multiple units tended to be less concerned with keeping training current, but this effect was not universal.
6. Forty percent responded to the open-ended question regarding changes to the hardware and to maintenance procedures that would ease maintenance. Twenty-three percent responded to the question regarding an instrument that would simplify maintenance. From these responses, two items were mentioned more than once. Fifty percent of respondents indicated that a simulator for connecting to the system would be helpful. Thirty-eight percent indicated that more detailed, clearer procedures would be helpful. Note that all of these relied heavily on the GE field line up instructions for their maintenance. The remaining comments ranged from simply using a better recorder to using a digital pressure set point pot to complete redesign of the system cards.
7. Forty percent of the respondents indicated that troubleshooting procedures existed. For many of these, the procedures were described as procedures that were prepared on a case-by-case basis. For the most part, there was satisfaction with the process. A few (10%) indicated the procedures were too inflexible, while another 10% indicated that the system documentation was inadequate.

8. Fifty percent indicated that there were cases where troubleshooting a problem was particularly difficult. The key problems mentioned are with:
   - Troubleshooting relay logic
   - Wiring and noise
   - TSI vibration trip
   - Dual ground
   - On-line troubleshooting
   - Three kHz oscillator noise
   - F/V card failing only at slightly below operating speed
   - F/V card with an incorrect capacitor installed
   - FASV-P port orifice lacking
   - Investigation ends with no problem identified

   (Note: These items are quite different in context and in the techniques needed to find them.)
9. Thirty-two percent of respondents addressing troubleshooting answered the item regarding procedure changes; 27% responded to the item regarding a troubleshooting device. For the instruments, most responses indicate that ordinary oscilloscopes, DVMs, strip chart recorders, and signal sources are suitable for troubleshooting. One of the responses indicated that either simplified relay logic or some sort of relay test device would be useful. A few indicated that a data acquisition system connected to a well-chosen selection of data points is useful for troubleshooting and perhaps for predictive maintenance. Other suggestions range from improved document control, to more test points on the front of the cards, to isolated test points, to installing the ability to disable turbine trips.

4.2.5 Miscellaneous Items

These items were intended to gather information on several issues. The results are:

1. Ninety percent indicated that upgrades and modifications generally performed as intended and did not cause additional problems. The exceptions:
   - Modifications that increase the outage time needed to complete the PMs.
   - Modifications that have resulted in an unexpected behavior, such as an alarm during testing.
   - Switches were installed in the CIV test circuit to eliminate an expected electronics problem; fix did not work because the problem was a lack of orifices in the FASV-P ports.

- Switch for turbine trip bypass was ineffective because it did not disable the redundant valve close signal.
- Contacts of a new 125 VDC relay board welded shut from the inductive kick of XK relays and caused a plant trip.

2. The replacement parts status, as viewed by the respondents is:
   - Fifty-five percent had long lead time on some items
   - Twenty-three percent had quality problems with some parts
   - Ten percent had problems with compatibility between the old and new parts
   - Sixty-four percent had immediate or impending replacement part problems

   Seventy-three percent responded to the question regarding inventory status. Of those, 54% had sufficient spares to last for quite a while, and one had sufficient spares to last for the life of the plant. Twenty percent thought they would have a problem if failure rates were to increase or have multiple failures in a short time. Another 10% had adequate inventory status, but only for a relatively short period. Twenty-seven percent of the respondents belonged to an inventory sharing program, but most of those shared inventory by virtue of being in a utility with multiple nuclear sites.

3. Third-party vendor activities include root cause analyses (35%) and board refurbishments (45%).
4. Survey data indicated that ongoing EHC operation and maintenance support provided from GE varied. Survey results indicated that utilities with on-site GE representatives or available local representatives received timely response from GE. Utilities had more difficulty when dealing with GE headquarters.
5. Twenty-seven percent of the respondents included an estimate of their maintenance cost. The cost breakdowns were given in different terms, so comparison between them is not definitive. (See Appendix E, Item 45 comments, for the responses.)

4.3 Conclusions

The general observations from the surveys are:

1. The variation in the implementation of modifications is not surprising. The modifications are used to solve specific problems that do not occur at all plants, and in some cases occur at a small number of plants.
2. The variation in test intervals is surprising. Extending test intervals at some plants may be possible and could be beneficial.
3. The perception of the predominance of hydraulic problems does not match the relative number of events in Section 3. However, this may be because many hydraulic problems do not appear in the industry databases.

4. The variation in responsiveness of the turbine vendor appears to be due to the varying capability of the local representative to handle the problems on their own. The responses indicate that most delays were caused by lack of timely response from the vendors' headquarters.
5. The differences in the devices responsible for problems at the different facilities are consistent with the data in the previous section where there is no single component or group of components that dominates the problems.

5

CONCLUSIONS

5.1 Introduction

The previous sections have reviewed the history of the performance of the GE EHC systems in nuclear power plants. First, in the larger sense, by reviewing the history of problems with the system that have been documented in industry databases. Second, by obtaining information directly from those who are responsible for the systems. Both sets of information were collected with the intent to provide information that can be helpful in maintaining the systems.

The event history shows a clear trend of increasing failures in the Mark I systems and decreasing failures in the Mark II systems. Unfortunately, there is no “smoking gun” in the event data because there is no particular component or group of components that are a major cause of the problems. The trends do not necessarily show up for a particular site because—fortunately—there are not enough events at a site to be statistically significant. This was confirmed by looking at data from three dual-unit sites with Mark I systems. One showed an increasing trend, while the others were flat.

The survey results provide details regarding the operation and maintenance of the EHC systems with a large number of respondents indicating that, overall, the systems were reliable and robust (usually with an “if properly maintained” caveat). The majority were from sites with Mark II systems, but about one-third were from Mark I sites.

5.2 Procedure Recommendations

The survey included several observations that the field lineup instructions contained quite a few errors, were not plant specific, and were not always clear. The recommendation is that the plants should prepare their own procedures with virtually no reliance on the field lineup instructions. There are several advantages to this approach. These include:

- Correcting the problems and nonspecific areas of the vendor field lineup instructions.
- Making it easier to incorporate system upgrades, system modifications, and devices from after-market vendors of EHC components into the procedures. The flip side is that the calibration procedure becomes a design input into the implementation of a particular upgrade rather than an afterthought.

- Obtaining consistent results between personnel and between calibration intervals because they are consistent with the plant specifics.
- Making a site-prepared procedure more consistent with the instruments and other calibration devices and processes used at the site.

Considerations to include in the procedures are:

- The extent of data recording should include the key as-found and as-left measurements. Secondary measurements should be included if they are potentially useful for future trending.
- The inspection of the contacts on any connector that is disconnected as part of the calibration and cleaning the contacts, if necessary. (Some survey respondents stated that the ground offset between cabinets was increasing. This could be evidence of increased connector contact resistances. In addition, poorer contacts—particularly on ground connections—can increase sensitivity to noise spikes, such as from relays.)
- The acceptance criteria to be used for any measurement must be carefully considered. The as-found vs. as-left data from previous calibrations will provide useful information regarding a suitable as-left adjustment criteria. In any case, the as-left acceptance criteria should be conservative.
- The issue of flexibility is somewhat tricky because “flexible procedure” is an oxymoron. However, there has to be significant reliance on the observations and judgment of the person performing the lineup. Electronic devices are too creative in the methods used to reveal degradation to include all possibilities in a procedure that fits into the control room.
- A reasonable warm-up criteria should be included in the procedures.

The actual number of procedures used does not appear to be significant. The most important consideration in this regard is to ensure that the various procedures are consistent with each other, that everything is covered somewhere in the package, and that there are reasonable transitions between them.

The overall responses to the survey indicates that most of those who had prepared their own procedures were satisfied with them, while those who relied heavily on the vendor instructions usually expressed some degree of dissatisfaction with them.

5.3 Lineup Interval Recommendations

The lineup interval to use involves some trade-offs. A frequent interval reduces the potential for drift to become excessive and perhaps detects incipient problems before they manifest themselves when plant operation would be disrupted. The down side is that the performance of the calibration causes wear on some components (for example, the adjustment pots), and calibrations take time. However, a once-per-fuel-cycle calibration and lineup of at least those devices that can degrade turbine performance or cause plant trips should be used. A secondary benefit is that it helps to keep the technicians familiar with the system.

5.4 Discard vs. Rework Recommendations

This is basically a commercial issue. Given the scarcity of new parts, all sites will probably be forced into some degree of board rework. The rework can be performed by the utility, the vendor, or a third party. Independent of who does the rework, it should have the following elements:

- The rework is performed using suitable equipment by individuals who are trained in the use of the equipment, and the board is properly cleaned after rework. The use of military specifications or other standards is a good practice, but it is not essential as long as the work is of high quality and the equipment used to perform the work is kept in good condition.
- A post rework burn-in is done, at least in cases where an active device is replaced. The burn-in should be at least 100 hours, with 300 hours preferred (current mil spec 883 is 336 hours).
- A complete post-burn-in calibration and performance test is performed. The test must include DC operation, rangeability, dynamic performance, load drive capability, and any other testing suitable to the function of the board (for example, to ensure a gate card will gate).
- A device that is old, or its age is unknown, should have the electrolytic capacitors evaluated for their remaining lifetime and replaced if near the end of life for the expected operation period of the device.
- A defined and auditable process for determining the suitability of substitute components is in place.

5.5 Bench Testing Recommendations

There are two types of bench testing to consider. One is a receiving inspection issue, and the other is a pre-installation issue. The receiving inspection test is partially a commercial issue. If a particular category of parts has a history of failure at receipt, then bench tests upon receipt is a good practice to ensure operable spares and that the warranty does not expire before a faulty device is discovered.

Pre-installation bench testing is basically a logistics issue. Bench testing will ensure that the device operates and that an initial calibration can be performed. This could reduce the installation time spent at the EHC cabinet, but it could increase the total time from removal from stores to final commissioning. If a minimum time at the cabinet is important for coordination with other activities or there are access problems for a particular device, then bench testing is a good practice. If on-site rework is done, then bench testing becomes essential.

5.6 Surveillance Test Recommendation

As there is a broad range of test intervals between plants, any plant with short test intervals (that is, weekly) should carefully review the basis for the test interval. Test intervals that appear excessive when compared to other plants should also be reviewed. (See Appendix E for the test interval distributions.)

5.7 Specific Component Recommendations

Even though the event data presented in Section 3.0 did not identify a specific component or group of components that were particularly troublesome (nor did one stand out in each of the individual items in the survey), there were a few components that were mentioned under different categories in the survey; however, none mentioned what the range of problems were or what was done about them. The items were: the card-mounted mercury relays, the power supplies, the calibration pots on the circuit cards, and the light bulbs. The recommendations to improve maintenance on these components are as follows:

1. The mercury relays presumably are replaced because they are still available. However, if the problem is short lifetime, then an alternate device should be investigated. It is possible to take a solid-state device and mount it on a transition assembly so that it will fit into the existing hole pattern. There are a sufficient number of devices in the fleet, and the design / assembly is sufficiently low cost to make this feasible. However, the characteristic of solid-state devices needs to be carefully evaluated in terms of the behavior of the existing relays. The important considerations are:
   - the state of the device when power is lost
   - the solid-state devices have an on-state voltage drop that could increase the heat load
   - the solid-state devices have a leakage current in the off state, which can be a problem in some circumstances (For example, a neon lamp connected to some types of solid state relays will never go out.)
   - the solid-state devices do not come in special configurations, such as make-before-break
2. The power supply problem has already been examined, but it is unresolved. It appears that most facilities are refurbishing the ones they have. In the long term, this may not be adequate. The surveys did not mention the details of the problem of finding a suitable replacement or whether a workable replacement had been found. There are probably form factor concerns as well as power supply performance concerns involved. The only recommendation based on the available information is that the design be reviewed to determine the power supply requirements necessary to support system operation, particularly with regard to operating temperature range, regulation, and ripple.

3. The calibration trim pots should be replaced if they appear to have dead spots in them. The pots are still available and are easily replaced. Note that some calibration adjustments (for example, op amp offsets) serve to reduce the temperature sensitivity of the device as well as to improve the performance.
4. The light bulb problem is one of burnout, and the problems with replacing them without shorting the power supply. They could perhaps be replaced with some sort of LED assembly, but they are not as bright as the bulbs. Also, no white LED exists. The simplest way to extend the life of a light bulb is to reduce the applied voltage; however, reducing the voltage is probably impractical. Perhaps there is a bulb of the same configuration that is rated at a higher voltage, but still have adequate brightness at the EHC voltage. The shorting problem has a conceptually simple, but probably impractical, solution. Installing a dropping resistor and a lower voltage bulb should prevent the shorting from overloading the power supply. However, the large number of bulbs involved makes the actual installation quite difficult.

5.8 Maintenance Personnel Issues

For these systems, it is best to use a select group of technicians who are familiar with the system to perform all but the most basic maintenance on them. This is necessary to ensure that the knowledge of the system is kept reasonably current and that the work performed on them is of the highest quality. Technicians need to be trained in the design and function of the system and its subsystems and in the behavior of the individual circuit cards. A basic knowledge of control system theory should also be included in the training to gain an understanding of the purpose of some of the devices.

5.9 Maintenance and Troubleshooting Aids

The surveys indicate that a significant number of the respondents would like a simulator to aid in maintenance. The response did not provide enough detail to determine exactly how a simulator would be used, only that it would simulate specific plant characteristics at power. The basic simulation needed to calculate the conditions could probably be quite simple because detailed dynamic response characteristics are probably not required. A more difficult problem might be connecting the simulator to the EHC, depending on which signals are to be acquired and which are to be generated. A specific definition of what a simulator should do is needed. The desire for a simulator is probably related to the plant startup problems mentioned by many of the respondents. A simulation of power conditions could help to confirm operation at various startup conditions. A plant interested in this device should prepare a set of requirements for it—preferably in conjunction with other sites—to define whether or not it would be feasible and useful.

The other devices mentioned in the surveys indicate that ordinary instruments are adequate for most of the maintenance.

For the difficult to diagnose problems given in the survey, there does not appear to be an easy solution. All are inherently hard problems to diagnose because in every case it is difficult to create the necessary conditions for diagnostics. The relay logic problem may be the exception because it appears to be primarily an accessibility issue, but it would probably require modification to the hardware itself. Having a number of on-line data signals could perhaps have helped for some of the cases. A few carefully selected on-line data acquisition points could have been useful. The points should be at least sufficient to determine if the behavior of a group of components (for example, the speed loop) is correct.

5.10 Obsolescence Issues

The vendor has indicated that the support for these systems could be withdrawn, and some of the survey responses indicated that special design boards and other devices—in addition to the power supplies mentioned earlier—are already in use. The potential solutions range from complete replacement to keeping the current system as-is. Short of complete replacement, several of the survey respondents indicated they were considering using a third-party vendor of EHC boards. At least one has installed boards from a third party and also is planning to install a digital load set from one. Others are counting on using board repair to keep them operating, at least in the short term. Many feel that they have sufficient spares to last 10 years or more; a few think trouble could come sooner than that. The BWR Mark II plants have a more complicated obsolescence problem because the SB&PR equipment is from a different division—and the cards have a completely different form factor—than the EHC equipment. Even those plants that plan to replace the entire system need to consider maintenance issues in the short term because a complete replacement will not happen overnight. The things that must be considered for the near- to mid-term are:

- The third party-vendors are geared to supporting the fossil plants. They probably will not produce any of the cards that are unique to nuclear power plants—at least not without serious prodding.
- The possibility of using some Mark II components in Mark I systems should be considered. There are some instances where the substitution could be quite straightforward. This may help reduce the failure rate trend for Mark I systems as well as provide a larger potential customer base for vendors of the components.
- The BWRs should consider converting to the Rosemount MSPS that have been installed in many facilities. The main problem associated with them is radiation damage (if inadequately shielded); a few plants have had problems with the signal conditioning cards.
- A plant that does not have an active repair program should at least investigate initiating one.
- The EHC systems are, in the full context, big, complex, systems; however, at the board level, they are not complicated. There are some complex circuits, but they are in the minority. Also, the design is basically conservative, even for its vintage, which is the reason Mark I and Mark II systems have been reliable in most ways.

APPENDIX A
EVENTS FOR BWR PLANTS WITH MARK I EHC

DATE	TYPE	NARRATIVE
3/03/84	Forced PressSwt TSI Spurious	During the weekly turbine test preventative maintenance activity, the main turbine tripped on a spurious trip of the turbine thrust bearing wear detector (TBWD) pressure switches. The turbine trip caused an automatic reactor scram. Investigation concluded that the TBWD pressure switch trip was a spurious occurrence. A blocking relay was replaced in the TBWD circuitry. (LER# 8413)
2/10/86	Turb. P.E. Proc Forced	With the unit at 99.8% power, a full reactor scram occurred as a result of high neutron flux (flow biased). The neutron flux spike resulted from an increase in reactor pressure that was caused by unexpected closure of the turbine control valves. A ground in the EHC circuit caused the turbine control valves to close. The cause of the ground was unknown, but suspected to have resulted from testing activity that involved temporarily connecting a digital voltmeter in the circuit to monitor EHC signals. (LER # 8611)
10/27/87	Forced Turb.	Shutdown for turbine EHC maintenance.
11/18/87	AtSD Turb. Proc	LER 387-87035-00 At 1511, on November 18, 1987, an unplanned engineered safety feature (ESF) actuation occurred on Unit 1. Utility instrumentation and control (I and c) techs were performing surveillance test 18 month time response test of RPS and eoc/rpt trips turbine stop valve and turbine control valve fast closure (si-183-413) when a main steam isolation valve (MSIV) closure signal was generated. The MSIVs were closed prior to and after the closure signal was generated. The actuation was the result of leads lifted from the panel side rather than the field side of a terminal block during the surveillance test. The leads were relanded and the actuation signal was reset. The surveillance was reperformed by lifting the field side leads and was completed without incident. The cause of the event was a deficiency in an approved procedure. Si-183-413 did not specify lifting the field side or the panel side leads. The event will be reviewed at the next I and c monthly shop meeting. In addition, si-183/283-413 will be revised. An existing note preceding the list of leads to be lifted will be expanded to specify lifting leads on the field side only. The prerequisites/limitations will be revised so that the surveillance can only be performed in plant conditions 4 and 5 with the MSIVs closed. A procedure step will be added to install a jumper to prevent the main condenser low vacuum bypass for the MSIVs from defeated.
11/29/87	Turb. LmtCycle LoadRed	Load reduction to 99% due to EHC servo current oscillations.

DATE	TYPE	NARRATIVE
2/18/88	AtSD Turb. Proc	LER 325-88007-01 During Unit 1 shutdown for a scheduled maintenance outage, a primary containment group 1 isolation signal occurred at 1725 hours on 2/18/88, approximately one minute after the reset of a main turbine trip signal resulting from too high reactor level. The unit main steam isolation valves were already closed. Reactor level was returned to normal and within approximately 10 minutes, the group 1 signal was reset. The safety significance of this event is minimal. This event resulted from inadvertent opening of the main turbine stop valves (TSVs), initiated by a spurious momentary power interruption to the main turbine mode selection circuitry, when the turbine trip signal was reset. Procedural changes were implemented to prevent inadvertent openings of the Units 1 and 2 TSVs during appropriate conditions. The subject circuitry problems for both units were investigated during outages. Testing on Unit 2 identified the same problem, and adjustments were made to various EHC components to prevent the problem. During the functional alignment on Unit 1, the event could not be repeated.
3/18/88	Forced Turb. Proc	LER 366-88006-00 On 3/18/88, at approximately 0920 CST, Unit 2 was in the startup mode of operation at an approximate power level of 172 mwt (approximately 5% of rated thermal power). The main turbine was in the tripped condition. Plant personnel were performing a functional test of the turbine control valve fast closure scram instrumentation. the removal of electrical links, to remove the less than 30% power scram bypass feature, resulted in an unplanned scram. Later, one main steam line drain isolation valve (eiis sb) failed to close on the expected group 1 signal due to loss of condenser vacuum. The valve did not receive the isolation signal. The scram was caused by a deficiency in the procedure, which failed to provide proper instructions for performing the functional test. Removing the bypass for both channels at the same time, when the control valve closure signal was present, resulted in the scram. The cause for the valve not receiving the isolation signal could not be determined. Corrective actions for this event included issuing a procedure revision, investigating the lack of isolation signal to the group 1 valve, and demonstrating the valve would isolate in response to the group 1 signal.
5/24/88	AtSD Proc Turb.	LER 388-88009-00 On May 24, 1988 with Unit 2 in condition 5 at 0% power, an ESF actuation occurred when an isolation signal to the MSIVs was initiated when an I and c technician pushed in a printed circuit card part way to avoid interference with the door to the EHC cabinet. This event was determined to be reportable per 10 CFR 50.73(a)(2)(iv), in that the inadvertent MSIV isolation signal constituted an unplanned ESF actuation. Adequate protection against an outside release of radioactive material was ensured during the event because the MSIVs were already closed in their safety function position. The EHC printed circuit card had been pulled out to facilitate troubleshooting for an EHC problem on the main turbine. When the card was partially reinserted, design conditions were met to initiate the MSIV isolation trip logic. The cause of the event is an I and c department program error governing normal work practices. It has been I and c work practice to leave circuit cards in the shelf position (pulled, but still in position) for situations when it has been necessary to remove them during work activities. Immediate corrective actions included pulling out of printed circuit card and resetting the isolations logic and associated alarms. The I and c work practice of leaving circuit cards pulled but left in the shelf will be discontinued for all circuit cards that cause trip functions. The event will be discussed at the next I and c shop meeting and the change in the I and c work practice will be emphasized to the appropriate personnel.

DATE	TYPE	NARRATIVE
8/26/88	Forced TSI Swtch Fail	The plant was at 100% power and the weekly main turbine functional test was in progress. The thrust bearing wear detector (TBWD) was being tested when a turbine trip occurred, which caused a reactor trip. A spurious reactor vessel water level 8 (+54 inches) trip was generated and all reactor FW pumps tripped. The HPCI system initiated at level 2 (-38 inches) and injected for approximately 90 seconds before being secured. The C-FW pump was restarted to maintain level and the reactor was stabilized. The root cause of this event was a loose TBWD drive motor switch actuating arm, which prevented the drive motor runback and actuation of the trip function lockout switches, resulting in the turbine trip. During the reactor trip transient, safety/relief valve (SRV) P failed to open due to a logic card failure and SRV-M opened below its set point. (LER# 8822)
11/10/88	Forced Turb. Noise PLUCard	LER 325-88024-01 On November 10, 1988, at 2025 hours, the Unit 1 reactor scrammed due to a momentary turbine control valve fast closure circuitry trip. The initiating signal is believed to have resulted from electrical noise in the turbine EHC system during the performance of a weekly power/load unbalance (PLU) test. The unit was brought to cold shutdown and scheduled refueling outage was started a day early. Troubleshooting efforts determined that the reactor protection system received three out of four inputs from the Turbine control valve fast closure circuitry due to a suspected hydraulic pressure transient induced by the spurious closure of the intercept valves caused by electrical noise generated by the PLU test relays. During this event the unit was operating at 71.6% power. The reactor core isolation cooling system, automatic depressurization system, A and B residual heat removal/low pressure coolant injection systems, and the A and B core spray system were operable and in standby readiness.
12/17/88	Forced P.E. Proc Turb.	LER 321-88018-00 On 12/17/88, at approximately 0002 CST, Unit 1 was in the run mode at approximately 2080 cmwt (approximately 85% of rated thermal power). At that time, the main turbine tripped on loss of EHC system pressure resulting in a reactor scram on the Turbine Stop Valve closure. Upon transfer of the nonessential loads to the startup auxiliary transformer 1d (as expected following a reactor scram). Sat 1d protective relaying actuated resulting in a loss of power to the Unit 1 nonessential loads. The cause of the scram was apparently personnel error in that a non-licensed operator implemented a system clearance on the EHC system of the wrong reactor unit. The cause of the sat 1d failure was equipment failure. Specifically, malfunctioning transfer relaying resulted in a trip of the transformer supply breaker. Corrective actions include training of operations shift personnel and replacement and calibration of transformer differential relay.

DATE	TYPE	NARRATIVE
12/25/88	Forced Turb. LimitSwt Fail	LER 366-88024-00 On 12/25/88, at approximately 0510 CST, Unit 2 was in the run mode at an approximate power level 2202 mwt (approximately 90% of rated thermal power). At that time, both reactor recirculation pumps tripped while performing the weekly surveillance on Turbine Stop Valves (TSVs). The unit was manually scrammed immediately as required by Unit 2 technical specification section 3.4.1.1, action a. Following the manual scram, reactor vessel water level decreased to the primary containment isolation system valve group 2 isolation set point and all group 2 valves isolated as designed. The root cause of this event is component failure. The roll pin in the actuating arm of the limit switch for TSV number 4 was broken. This prevented the TSV from picking up the actuating arm when the valve was open fully. As a result, the recirculation pump trio logic sensed TSV number 4 less than 90% open. When TSV number 2 was closed for testing, the logic was satisfied and both recirculation pumps tripped per design. The corrective actions for this event included repairing the failed limit switch and revising TSV and turbine control valve testing procedures.
3/22/89	LoadRed Turb.	Load reduction due to control valve fast closure test circuit problem.
4/06/89	Forced Turb. Wearout Solenoid LimitSwt Fail	Automatic trip from 80% power on turbine stop valve closure during turbine-generator testing due to turbine trip pilot solenoid valve (PSV) failure and sticking limit switch contacts caused by aging and cyclic fatigue. PSV-A overheated and shorted. With PSV-A failed in the deenergized state, the PSV-B deenergized when the operator put the test switch in the test position causing the master trip solenoid valve to trip. The level transient following the reactor trip caused containment isolation and SGTS actuation. (LER# 8901)
4/12/89	Forced SB&PR MCFL Fail	A circuit board in the maximum combined flow limit circuit in the electrohydraulic system failed, causing the turbine control valves to fail closed due to decreasing output from the circuit board. Closure of the turbine control valves caused the turbine bypass valves to open as designed to control reactor pressure. The bypass valves then began to malfunction. Some of the bypass valves would not reseat when reactor power was reduced due to failure of the opening bias potentiometer. The reactor was manually scrammed from 64% power following a load reduction from 75% power on 4/11/89, due to increasing reactor pressure. The ensuing level transient actuated containment isolation and standby gas treatment. (LER# 8903) LER 254-89003-00 On April 12, 1989, Unit 1 was in the run mode at approximately 74% of rated core thermal power. At 1136 hours, a manual reactor scram was initiated due to main turbine bypass valves opening. One bypass valve had oscillated open during the night before, but at 1126 hours, all nine bypass valves had opened in sequence. NRC notification was completed at 1210 hours to comply with 10 CFR 50.72 (b) (2) (ii). An investigation revealed that the cause for this event was component failure. A circuit board within the combined maximum flow limit circuit had a decreasing output. The board limits the opening of control valves, and as a result of the decreasing output, caused the control valves to close. The bypass valves were opening as designed to control reactor pressure. The circuit board was replaced. This report is provided to satisfy 10 CFR 50.73 (a) (2) (iv).

DATE	TYPE	NARRATIVE
4/15/89	Forced Fail Relay Turb. HiOhm	High contact resistance due to normal component wear on a normally open contact caused all turbine stop valves to fail closed during surveillance test resulting in a reactor trip. The main generator failed to trip due to the reverse power relay failing due to dirt in the relay. (LER# 8906) LER 249-89006-00 On April 15, 1989, at 0320 hours, with Unit 3 operating at 92% rated core thermal power, a reactor scram occurred during surveillance testing of the main turbine stop valves (TSVs). The cause of the scram was determined to be component failure. High contact resistance on a normally open contact prevented its required closure during testing of the TSV-2. This failure resulted in the remaining three TSVs starting to close when TSV-2 started to close. Also during this event the main generator output circuit breakers failed to open on reverse power. Consequently the main turbine was manually tripped at 0323 hours. The root cause of this failure was also attributed to component failure. Upon inspection of the main generator secondary reverse power relay, dirt was found between the bearing and contact pivot arm on the relay directional unit preventing proper operation. As corrective actions for this event two TSV control relays were replaced. The main generator secondary reverse power relay was cleaned and verified to operate properly. To help prevent future failures of reverse power relays the calibration procedure will be revised to specifically address mechanical binding of the contact pivot arm. Prior to unit startup all of the turbine control valves, stop valves, and combined intermediate valves were functionally tested. The safety significance of this event was considered to be minimal because all reactor scram functions operated properly and the primary reverse power relay was available to prevent damage to the main generator. Two previous similar occurrences were reported by LER 89-002/050249 and LER 86-025/050249.
4/22/89	Forced Turb. P.E. Proc	While preparing to perform weekly turbine backup overspeed trip testing, an operator keyed a radio within the vicinity of the EHC cabinet. This action caused EHC system disturbances resulting in inadvertent movements of the turbine control and bypass valves. This created a pressure spike that caused all six average power range monitors to exceed their upscale trip set points, tripping the reactor. (LER# 8909) LER 410-89009-00 On April 22, 1989, at 1941 hours, Unit 2 experienced a reactor scram as a result of a neutron monitoring system trip. Specifically, when preparing to perform weekly turbine backup overspeed trip testing an operator keyed a radio within the vicinity of the EHC cabinet. This action caused EHC system disturbances resulting in inadvertent movements of the turbine control and bypass valves. This malfunction created a pressure spike that caused all six average power range monitors (APRMs) to exceed their upscale trip set point. At the time of the event reactor power was at 100% rated thermal power. The root cause for this event was human performance problems. Corrective actions taken for this event were: (1) issuance of a training modification request to ensure appropriate personnel are aware of potential problems with radio use; (2) installation of permanent caution signs at each entrance to the relay room; and (3) issuance of a memorandum from the station superintendent to all station personnel concerning use of radios/beepers. In addition, other areas of the station that have been identified as radio transmission sensitive have been posted.
5/06/89	Forced Turb. CardNS	Turbine was taken off-line to replace electrohydraulic control boards.

DATE	TYPE	NARRATIVE
5/12/89	Turb. Proc Forced	LER 352-89032-00 On May 12, 1989, a full reactor protection system (RPS) scram signal was generated during performance of main turbine control valve surveillance testing. There was no control rod motion because the reactor was in cold shutdown with all control rods inserted. The cause is procedural inadequacy as there was no clear indication of the plant configuration required for performance of the test with the plant in a shutdown condition. This event could not have happened with the unit operating because the ambiguous steps of the procedure would be inapplicable and not performed. The consequences of the event were minimal because the unit was in cold shutdown. The test procedure was corrected and reperformed satisfactorily. The procedure will be permanently revised to provide clear guidance to the performer.
6/29/89	Forced Connection MMI Fail Short	Automatic scram from 94% power due to spurious turbine trip caused by condenser vacuum switch indicating lamp loose wire connection. Induced voltage from the loose connection energized relay K2D18, which energized the master trip bus and tripped the turbine. The ensuing level transient caused actuation of Group II and III containment isolation and standby gas treatment. Group I containment isolation (MSIV closure) occurred on low reactor pressure signal after the scram due to instrument rack vibration caused by steam impact on the stop valves. (LER# 8910)
7/19/89	LoadRed SB&PR	Main turbine electrohydraulic control system pressure controller problem caused load to be reduced.

DATE	TYPE	NARRATIVE
7/21/89	SB&PR MSPS Fail Forced Water	Turbine control pressure regulator set A pressure sensor failure. Noncurtailing event. (LER # 8915) Moisture condensed in an electrical conduit causing failure of a main steam pressure transducer. This caused drifting of the A pressure regulator in the main turbine EHC system. It was thought that the A pressure regulator was malfunctioning and an attempt was made to remove a card from the A pressure regulator and operate on the B regulator. However, moving the card caused a voltage transient in the regulator causing opening of the main turbine control and bypass valves. The resulting low steam line pressure caused MSIV closure that caused a reactor scram. Ensuing level and pressure transients caused actuation of main steam relief valves and additional containment isolations. (LER # 8915) LER 277-89015-01 At 2231 on 7/21/89 with Unit 2 at 79% thermal power, an attempt was made to remove a malfunctioning reactor pressure vessel (RPV) pressure regulator set from the electronic portion of the main turbine (MT) electrohydraulic control (EHC) pressure regulating system. Immediately, the MT bypass and control valves opened, causing main steam line pressure to decrease to approximately 480 psig. At 850 psig main steam line pressure a Group I isolation occurred causing the main steam isolation valves (MSIV) to close. As a result, a full reactor scram occurred. RPV level decrease due to shrink following MSIV closure resulted in a Group II and III isolation as level decreased below 0 inches. Two main steam relief valves (MSRV) lifted once automatically, followed by manual operator cycling of MSRVs to control RPV pressure between 930 psig and 1,060 psig. The high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems were placed in operation to control RPV pressure and level. The root cause of this event was a malfunction of the electronic portion of the a RPV pressure regulator set. No actual safety consequences occurred as a result of this event. The majority of the a regulator electronic components were replaced. This event has been reviewed with appropriate plant personnel. One previous similar LER was identified.
8/25/89	LoadRed Turb. LimitSwt Grnd. Fail	LER 254-89012-00 On August 25, 1989, at 1045 hours, Unit 1 was in the run mode at 77% of rated core thermal power. Instrument maintenance (IM) discovered the supply wire (cbl) to the EHC system (tg) valve (v) test circuitry to be burnt through. A load reduction to less than 45% rated steam flow was initiated immediately because it was initially believed that a required scram function was inoperable. At 1100 hours, in accordance with the generating station emergency plan (GSEP), an unusual event was declared and a nuclear accident reporting system (NARS) phone notification was made. At 1122 hours, a nuclear regulatory commission (NRC) emergency notification system (ENS) phone notification was made to satisfy 10 CFR 50.72 (2)(1)(i). At 1220 hours, with load below 45%, the gsep unusual event was terminated. At 1845 hours, a ground on the number 2 control valve (fcv) test limit switch (33) was found and was determined to have caused the supply wire to burn through. The supply wire was replaced. The limit switch will be repaired. At 2120 hours, a turbine control valve fast closure functional test was successfully completed. The unit resumed normal power operations. This report is being provided as a voluntary report.

DATE	TYPE	NARRATIVE
8/26/89	Forced TSI Relay Fail Short	LER 331-89011-01 On August 26, 1989, at 1642 hours, with the plant operating at 100% power, operations procedure, power/load unbalance and relay circuits test was in progress. This test is performed for continued reliable operation of the main turbine. Contrary to what was expected, a trip of the main turbine control valves and subsequent reactor scram occurred at 1643 hours. Subsequent detailed investigations identified bridging of a mercury-wetted relay in the power/load unbalance circuitry as the most probable root cause for the turbine trip and subsequent reactor scram. Approximately five minutes following the scram, problems were encountered on the B essential and non-essential busses. Subsequent investigation revealed the root cause to be a failed trip coil on an associated breaker. The plant was brought to a normal, safe shutdown condition and the appropriate notifications were made. There was no effect on the safe operation of the plant.
10/05/89	Forced Fail	EHC Card Failure
11/2/89	AtSD Turb. P.E. Proc	LER 388-89013-00 At 1055 on 11-2-89, with the unit in cold shutdown, an unanticipated main steam isolation valve (MSIV) isolation signal was generated by the primary containment isolation system (PCIS). At the time of the event, the main condenser was at atmospheric pressure, the main turbine stop valves were closed, and the automatic isolation signal from the PCIS to the MSIVs and main steam line drain valves on low main condenser vacuum was disabled per plant operating procedures. An I & c technician, who was working in a main turbine control panel, inadvertently applied 24 VDC to an incorrect terminal point that caused the main turbine stop valves to open. This in turn re-enabled the automatic MSIV isolation on low condenser vacuum. This event was determined to be reportable under 10 CFR 50.73(a)(2)(iv) in that the unanticipated PCIS signal constituted an unplanned actuation of an engineered safety feature. A review of this event will be conducted with all appropriate I & c personnel. Expanding the scope of a procedure used to defeat specific trip signals during certain I & c work activities is being evaluated. Any procedure enhancements will be based on the conclusions of this evaluation. Since all systems and components functioned properly, there were no safety consequences to the health or safety of the public nor would there have been had the MSIVs been open and the reactor vessel pressurized (the MSIVs and main steam line drain valves would have closed as a result of the automatic isolation signal).

DATE	TYPE	NARRATIVE
11/05/89	Forced Turb.	Electronic control card in electrohydraulic control system failed, causing bypass valves to fail open and control valves and intercept valves to fail closed causing a turbine trip. The reactor tripped on high flux. The void collapse caused actuation of RCIC, containment isolation, and standby gas treatment. HPCI was out of service at the time. One safety valve lifted below its set point. (LER# 8920) LER 333-89020-01 Update report-previous report date 12-5-89 results of EHC board tests eiis codes are in () a reactor scram occurred from full power at 3: 23 pm on November 5, 1989. An unidentified failure in an electronic control card of the EHC (jj) system for the main turbine (ta) is believed to have opened the bypass valves and closed the intercept and control valves. This reduction in steam flow caused a pressure transient resulting in a reactor high flux scram signal from the average power range monitor (APRM) (ig). The high pressure coolant injection (HPCI) (bj) system was inoperable prior to the scram. The automatic features of the plant responded normally to the scram except that one safety relief valve passed a small amount of steam at a pressure 5% below its design lifting pressure. The reactor core isolation cooling (RCIC) (bn) system was used to restore reactor water level. One control rod was not fully inserted, requiring manual insertion from position 02. Selected electronic control cards were replaced in the EHC system. The plant was restarted 11-10-89, and scrammed 11-12-89 (LER-89-023) for unrelated reasons. The plant was restarted 11-13-89 and run at 25% power to observe the EHC system. It was shutdown 11-20-89 for further work on the EHC system. Following testing and replacement of additional electronic circuit boards, the plant was restarted on 11-22-89. The circuit boards removed from the EHC system have been sent to the vendor for analysis and possible root cause determination. Factory testing showed that all nine analog speed control boards met original equipment standards. No defects were found.
11/15/89	LoadRed	Load reduction for turbine electrohydraulic control testing and investigation.
11/20/89	Forced Turb.	Shutdown for electrohydraulic control circuit boards replacement.
12/01/89	Forced Turb. Fail	While at 97% power, all five turbine bypass valves went full open and all four turbine control valves closed causing an increase in reactor pressure. The pressure increase caused reactor power to increase resulting in an automatic scram due to average power range monitor high neutron flux signals. The event was caused by a turbine EHC malfunction. The cause of the malfunction was a sudden zero voltage input to the control valve demand signal. Three relay boards in the EHC control circuit were replaced and a ground loop in the turbine speed sensing circuit was corrected. (LER# 8940) LER 410-89040-00 On December 1, 1989, Unit 2 was operating at approximately 97% rated thermal power with the mode switch in the run position (operational condition 1). At 1310 hours, Unit 2 experienced an automatic reactor scram caused by average power range monitor (APRM) high neutron flux signals on both divisions of the reactor protection system (RPS). At 1313 hours, the turbine was tripped on reverse power by the main generator antimonitoring device. Immediate corrective actions were taken by operations to carry out all scram recovery actions and to place the plant in a stable hot shutdown mode (operational condition 3). Operations then initiated an investigation of the event. The immediate cause was a malfunction of the EHC system that resulted in the power transient that caused the scram. Corrective action was to replace 3 relay boards in the EHC control circuit and correct a ground loop in the turbine speed sensing circuit.

DATE	TYPE	NARRATIVE
12/02/89	Forced Turb. Design	While shutdown following a scram on 12/1/89, the unit experienced a RWCU system isolation followed one minute later by a low reactor water level 3 scram. The low reactor water level occurred as a result of cycling of the turbine bypass valves during turbine EHC troubleshooting by technicians using a deficient print. The RWCU isolation was caused by a RWCU flow transmitters zero point shift upscale due to the oscillations in vessel pressure. The failed transmitters were replaced. (LER# 8941) The unit was taken to cold shutdown to investigate deficient turbine EHC diagrams and troubleshoot the EHC system following an automatic scram on 12/1/89 and another automatic scram signal on 12/2/89. See turbine EHC events on 12/1/89 and 12/2/89. (LER# 8940 and 8941) LER 410-89041-00 On December 2, 1989, at 0252 hours with the reactor mode switch in shutdown Unit 2 experienced an isolation of the reactor water cleanup system (WCS) and at 0253 hours an actuation of the reactor protection system (RPS). A reactor scram occurred, which was caused by the reactor water level dropping below the low-level 3 scram trip point. This level change was a direct result of cycling of the five (5) turbine valves. Valve movement occurred during instrument and control (I and c) technician troubleshooting of the EHC systems load control unit. At the time of the event, the reactor vessel pressure was 188 pounds per square inch gauge (psig); temperature was 383ºF. The root cause of the WCS isolation was component failure. The immediate cause of the RPS actuation was testing of the EHC load control unit. The root cause of the RPS actuation was a lack of understanding between the EHC system vendor and engineering. Initial corrective action was the restoring of normal reactor level by licensed operators. Additional corrective actions addressed the causal factors leading to defective documentation.
12/13/89	Turb. Proc Forced	Turbine trip per reactor trip 5.21 (testing) (post-refueling). LER 278-89011-00 On 12-14-89, 1053 hours, an operations support engineer discovered that two surveillance tests (ST), ST 9.4, turbine stop valve closure functional and ST 9.14, turbine control valve fast closure functional were not performed as required by tech specs. These tests were required to be performed prior to reaching 30% rated thermal power that was reached 12-13-89. The surveillances were performed satisfactorily on 12-14-89, 2000 hours. The root cause of this event was an incorrect standard practice of performing these surveillances after reaching 30% power. No actual safety consequences occurred as a result of this event. Appropriate general plant procedure(s) will be revised to ensure ST 9.4 and ST 9.14 are performed prior to being required operable. ST 9.4 and ST 9.14 will be revised as needed to allow performance prior to 30% power. A review of similar surveillances associated with reaching operational milestones will be performed. Appropriate revisions to these surveillances will be performed and programmatic controls will be established to ensure these surveillances are performed prior to reaching the milestones. Corrective actions will be complete by 6-1-90. There were no previous similar LERs.

DATE	TYPE	NARRATIVE
12/30/89	Forced TSI Fail LimitSwt	Limit switch failure during turbine thrust bearing detector surveillance test caused a turbine/reactor trip. Failure to execute a planned design change to the turbine thrust wear detector circuitry contributed to the event. (LER# 8925) LER 354-89025-00 On 12-30-89, at 1947, during the performance of the TBWD section of the main turbine monthly functional test procedure, a turbine trip occurred. This trip was followed immediately by a reactor scram via the reactor protection system on a turbine control valve fast closure signal. All control rods inserted, and plant systems responded as expected, with minor exceptions as noted in the text of this report. Investigation subsequent to the event determined that a TBWD limit switch had malfunctioned during the test, resulting in the turbine trip circuitry sensing that the turbine end thrust bearing had actually failed. While the initiating cause of this event was the TBWD limit switch failure, the root cause of this event was the inadequate prioritization of a design change that had been pending since 1988. This design change would have modified the TBWD circuitry to prevent a turbine trip signal while testing the TBWD. Corrective actions included implementing this design change, repairing the TBWD limit switch, reviewing all other scram reduction design changes for adequate prioritization, reviewing other turbine trip test procedures for administrative adequacy, and incorporating this event into appropriate training programs.
1/6/90	Forced Turb. Proc	LER 354-90001-00 On 1-6-90 at 0120, during performance of a surveillance procedure that tests the main turbine combined intermediate valves (CIV), the a moisture separator experienced a high level condition. In response to this high level condition, the associated dump valve opened, but not in time to prevent a turbine trip on moisture separator high level. Immediately following the turbine trip, the reactor scrammed on a turbine control valve closure signal from the reactor protection system. All control rods were verified to be inserted, and plant systems responded as expected, with minor exceptions as noted in the text of this report. Investigation subsequent to the scram determined that multiple causes combined to result in the scram-moisture separator level controllers not being optimally tuned and the cycling of a CIV prior to stabilization of moisture separator level after cycling a previous CIV. Corrective actions included tuning of the moisture separator drain control instrumentation loops, procedurally increasing the time between cycling of CIVs during the subject surveillance, counseling the nuclear control operator (NCO, ro licensed) who performed the surveillance, and including a review of the event during the next licensed operator requalification cycle.
2/24/90	AtSD Turb. Proc	LER 324-90002-00 While Unit 2 was in cold shutdown on 2-24-90, a group 1 isolation occurred when the undervoltage relay for the EHC system 125 VDC power supply was replaced, following recalibration for plant modification 86-058. The event was initiated by mode indication of the main turbine speed selection switch (eiis/ta/sis) changing from valves closed to 1800 rpm upon the swap of EHC power supplies when the undervoltage relay was reinstalled. The mode change coupled with the existing low vacuum condition (cold shutdown), initiated the group 1 isolation logic. Investigations into this event have determined that the cause of the event was the lack of recognition of the significance of having the turbine reset while performing EHC evolutions. No further corrective actions are considered necessary for this event. This event had no safety significance, as the reactor was shutdown for a planned outage.

DATE	TYPE	NARRATIVE
6/26/90	Forced Turb. LimitSwt Fail Open	LER 373-90010-00 On June 26, 1990, at 0453 hours, with Unit 1 in operational condition 1 (run) at 75% power, a reactor scram occurred during the performance of limited procedure llp-90-027, Unit 1 turbine stop valve (TSV) scram functional test . The scram occurred as designed, due to the closing of turbine stop valves 1, 3, and 4 after number 2 TSV was cycled and its open limit switch failed. It was discovered during the scram investigation that the number 2 TSV open limit switch (SVOs-2, non reactor protection system limit switch) had failed to the not open position. This failure occurred May 22, 1990 at 0359 hours, the last time this procedure was performed. At this time, the valve test logic of turbine EHC system sealed in the master/slave interlock. This prevents the other TSVs from closing while number 2 TSV is tested. On June 26, 1990 at 0453 hours, number 2 TSV was tested and closed to about 90% open. When the valve fully opened, limit switch SVOs-2 toggled to the open position (due to a loose mounting of the switch, caused by vibrations). This broke the seal-in interlock. A second later, it toggled back to give a not open alarm and commanded the other TSVs to go full close. The emergency core cooling systems (ECCS) and the reactor core isolation cooling system were available during the event. All other systems operated as expected during the reactor scram with exception of the 1b turbine driven reactor feedwater pump (TDRFP) that did not trip when the manual push button was depressed. The 1b TDRFP was subsequently tripped by using the overspeed test switch. The number 2 TSV limit switch mounting bolts were tightened and its circuitry tested. Temporary system changes and modifications will be installed to improve the logic to prevent recurrence of this type of event. The 1b TDRFP was tested and functioned as designed. This event is being reported to the NRC pursuant to the requirements of 10 CFR 50.73(a)(2)(iv) due to the actuation of an engineered safety feature system.
7/15/90	LoadRed Turb.	Load was reduced when turbine control valves #1, #2, and #4 failed to fast close during test.
8/19/90	LoadRed Turb. LimitSwt Fail	Load reduction continued due to turbine control valve #2 test limit switch failure discovered during test.
9/27/90	Forced Proc LimitSwt Fail Turb.	LER 325-90017-00 During a scheduled Unit 1 shut down for a refuel-maintenance outage on September 27, 1990, the reactor scrammed on high pressure at 0348, during the performance of periodic test (pt) 40.2.10, turbine control-stop valves (TCV-TSV) leak tightness testing. Prior to the event, the reactor was at approximately 22% power and the emergency core cooling systems (ECCS) were operable in standby readiness. Event recovery was in accordance with site emergency operating procedures, no ECCS or engineered safety feature actuations or isolations other than scram signals occurred. The event was occurred by erroneous procedural guidance, incorporated into the PT from a vendor document, and defective switches on the TSVs that allowed the TCVs to open when the TSVs were closing. This resulted in the turbine bypass valves (BPV) open demand signal being limited by the maximum combine flow circuitry of the turbine control system. The closure of the TBVs occurred reactor pressure to increase to the scram set point. Maximum power attained during the scram was 28%. This event had minimal safety significance as the reactor is analyzed for a high pressure scram from full power. Past high pressure scram events were reviewed and found not to be related to this event. The procedure will be rewritten and the switches will be repaired.

DATE	TYPE	NARRATIVE
9/28/90	Forced TSI Fuse Wearout Fail	Manual scram due to turbine electrohydraulic control fuse failure during torsional test.
10/20/90	LoadRed Elec Relay Fail	Loss of electrohydraulic control 125 VDC power transfer relay caused a load reduction.
12/4/90	None Elec PwrSup Fail	An EHC electrical malfunction annunciation was received on the EHC electronic controller (2-EHC-xy-644). The 30 VDC power supply in bay F of the EHC operator's control panels was found to be in the off position. Unit 2 was at 100% power on discovery date. The failure was due to a failed power supply (piece part of the controller) the power supply was found to be tripped. The root cause of the failure was do to an unknown circuit piece part. The failure resulted in a degraded system with no significant plant effect. the 30 VDC power supply (piece part of the controller) was replaced like in-kind. The EHC electronic controller was left in satisfactory condition. Taw 90-awgl1
2/09/91	Forced Turb. Noise	Electrical noise while the turbine bypass valve was cycled for testing caused electrohydraulic low oil pressure and resulted in a reactor trip from 100% power. Reactor water level shrink caused containment isolation actuation. The noise caused swapping of primary and backup main turbine speed error signals, resulting in a spike that appeared in the EHC logic as a turbine overspeed. This occurred during the reset portion of the test for the overspeed circuitry and trip valves. (LER# 9103) LER 331-91003-00 On February 9, 1991 at 1659, a reactor scram from 100% power occurred due to a sensed low control oil pressure at the main turbine control valves. Extensive troubleshooting following the event identified induced electrical noise in the turbine EHC system, which appeared to have ultimately caused the pressure fluctuation in EHC control oil. Corrective actions include shielding of appropriate cabling and additional, more frequent EHC system component preventive maintenance. All automatic actions occurred as designed as a result of the scram. Operator actions were appropriate and expeditiously returned the plant to a stable condition.
2/11/91	AtSD Elec Proc Breaker P.E.	Unit was in refueling with EHC pump train was in service. 2b EHC pump failed to start while 2a was already running. Operators tried to start 2b a second time unsuccessfully. Operators suspected a breaker problem. The train was lost with no impact on unit. Investigation found problem was with 480 volt breaker for 2b EHC pump. This breaker had been rebuilt earlier in the refueling outage. All readings were within limits but were on the low side. Amp check is not to exceed 185 amps and all three phases were below 100 amps. The cause of the failure was due to the breaker being out of adjustment. Removed breaker and bridge and meagered and adjusted B-phase. Installed breaker and successfully performed an amp check.
2/27/91	Forced Turb. P.E. Proc	During testing of the Turbine First Stage Permissive pressure switches, both reactor recirc pumps tripped because a test jumper had been left following the turbine control valve fast closure instrument functional test several days earlier. The recirc pump trip caused high vessel level that caused tripping of the feedwater pumps and the turbine. Turbine trip caused reactor trip. Containment isolation actuated on low level following the trip. (LER# 9107)

DATE	TYPE	NARRATIVE
4/12/91	Elec Connection Fail Forced Open	A turbine trip and automatic scram was caused by turbine EHC DC power supply failure. After the reactor trip, a radwaste operator misinterpreted indications from the condensate filter demineralizers (CFD) and isolated all 8 of the CFDs, which also isolated the suction flowpath for the reactor feed pumps. This caused the A RFP to trip on low suction pressure. Operators initiated RCIC to restore reactor level. Containment isolation actuated due to the level transient following the scram. The cause of the loss of the EHC DC power supply was due to a loosely fitting copper link found in the power supply cabinet (GE). The copper links were installed during construction of the EHC system. (LER # 9109) LER 352-91009-00 On April 12, 1991, a Unit 1 reactor scram and a partial group VIc primary containment and reactor vessel isolation control system actuation occurred following a main turbine trip. The main turbine trip resulted from a spurious loss of the 125 volt DC electrical power supply to the EHC system. Following the scram, all control rods fully inserted, reactor pressure increased to 1,103 psig, and level decreased to approximately minus 20 inches instrument level. The reactor core isolation cooling (RCIC) system was manually operated to maintain reactor level when a loss of normal feedwater injection occurred. All systems operated as designed except for the normal feedwater system in which operator interaction occurred. Operations personnel successfully controlled the plant shutdown using the appropriate plant procedures. The cause of the loss of the 125 volt DC electrical power supply to the EHC system was due to a loose copper link inside a switch cabinet. The cause of the loss of normal feedwater injection was due to a personnel error resulting from a misinterpretation of the indications for the condensate filter demineralizer system. The copper links were replaced with hard wire connectors, and an evaluation of other similar switch cabinets with copper links will be performed. Operator training will be implemented to address this specific loss of normal feedwater injection incident.

DATE	TYPE	NARRATIVE
4/15/91	AtSD Turb. Relay Bounce Fail	After the main turbine was reset during testing, a Group 1 isolation occurred. At that time, it was noted that the EHC logic had selected the 1,800 revolutions per minute (rpm) turbine speed mode that resulted in the opening of the turbine stop valves and the subsequent isolation of the main steam isolation valves. Unit 1 was at 0% power. The failure was due to the spurious selection of the 1800 RPS mode of the turbine speed control logic that was caused by the normally closed contacts of the kid 44 relay failing to maintain closure after the relay coil was deenergized upon turbine reset. The cause of the relay bouncing was unknown. The failure resulted in the loss of system with no significant plant effect. The relay card (piece part of the EHC controller-1-EHC-xy-644) was replaced like in-kind. The turbine had been reset three times before the EHC system functioned properly and testing was resumed. The EHC controller was left in satisfactory condition. LER 325-91010-00 The Unit 1 reactor was in cold shutdown. At 225853 on April 15, 1991, the main turbine was reset in accordance with the applicable steps of the turbine system operating procedure. At 230055 the main steam isolation valves (MSIVs) closed when a group 1, primary containment isolation system (PCIS) isolation signal occurred (i.e.; low condenser vacuum coincident with the main turbine stop valves not fully closed). At that time it was noted that the EHC logic had selected the 1,800 rpm turbine speed mode. Instrumentation and control personnel attached a brush recorder to the EHC circuitry. This monitoring revealed that the spurious selection of the 1,800 rpm mode was caused by the normally closed contacts of a relay failing to maintain closure after the relay coil was de-energized. The relay card in the EHC circuitry was replaced. A work request has been initiated to investigate the corresponding Unit 2 relay during the next refueling outage. The MSIVs operated as designed and closed in response to the PCIS group 1 isolation signal. The purpose of the PCIS signal that occurred during this event is to prevent a possible uncontrolled release of radioactive steam to the turbine building. The reactor was in cold shutdown, at atmospheric pressure, and being maintained at 144ºF; therefore, no radioactive steam was present. This event had no nuclear safety significance.
6/9/91	LoadRed TSI DrtyOil	During testing of the turbine bearing wear detector, foreign material in turbine bearing oil caused a turbine bearing wear detector trip. Following the turbine trip, the reactor tripped from 42% power due to increased reactor power and pressure resulting from the lack of additional turbine bypass capability and loss of FW heating. During the transfer of power to the auxiliary power transformer, Group I and II containment isolation occurred in the isolation logic when relays dropped out due to low voltage during the transfer. Groups II and III containment isolations occurred due to the reactor level transient following the scram. (LER# 9111)

DATE	TYPE	NARRATIVE
7/28/91	TSI Fail PLUCard LoadRed Wearout	With the unit at full power, operations personnel on routine rounds in the control room received an intermittent EHC turbine exhaust alarm from the pressure transmitter (pt) via the power load unbalance card (a01). Failure of this transmitter or the a01 would cause loss of power load unbalance trip to the main turbine. Though channel was lost, there was no significant effect on system or plant operation. (c0075982) DC the suspected cause of the failure was a defective power load unbalance card (a01) for reasons unknown. The power load unbalance card was replaced like for like. Card and PT were calibrated satisfactorily and returned to service reflecting current plant conditions. While at full power, control room personnel received the main steam low intermediate pressure alarm. The alarm comes from the power load unbalance (PLU) card (General Electric no 948d895). The PLU trip circuit was tested satisfactorily therefore turbine protection was maintained. Intermediate valve fast closure on 5% position mismatch was lost. Although the system was degraded there was no plant effect. Troubleshooting determined one of the power load unbalance card outputs failed due to a bad connection or broken conductor internal to the CRD and has been attributed to normal aging. This single output goes to both the alarm circuit and the intermediate valve fast closure permissive. The power load unbalance card was replaced like for like, calibrated per plant procedures to within acceptable limits, tested satisfactorily and accepted by operations for return to service.
8/17/91	Forced Turb. Valve Fail	During surveillance testing of the #2 turbine stop valve, its fast acting solenoid valve (FASV) failed causing a reduction in emergency trip system oil pressure, causing all six combined intercept valves to close (the #1 stop valve FASV had previously been erratic but had not caused a transient). The transient caused a generator trip that caused a turbine/reactor trip. Containment isolation and standby gas treatment also actuated. (LER# 9106)
8/25/91	LoadRed TSI Fail TBWD	Turbine thrust bearing wear detector failure during surveillance testing caused a turbine trip (cause not given). A scram was avoided by inserting rods. Following the generator trip, power transferred from the auxiliary to the startup transfer, causing a momentary dip in AC power. This caused relays for eleven containment isolation valves to close. Consideration was being given to replacing the AC relays with DC relays. (LER# 9117)
9/9/91	AtSD Turb. Proc	LER 410-91018-00 On September 9, 1991, at 1028 hours with the reactor at 0% power, all rods inserted, and the reactor mode switch in the shutdown position (operational condition 4), Unit 2 experienced an engineered safety feature (ESF) actuation. Specifically, while performing surveillance testing on the turbine control valve fast closure scram function, a full reactor scram signal was received from the reactor protection system (RPS) scram logic. The root cause for this event has been determined to be procedural inadequacy. Immediate corrective actions were to identify the cause for the RPS scram signal and reset the scram. Additional corrective actions include: combining the monthly RPS operations surveillance procedures into one procedure; revising operations surveillance procedure n2-osp-RPS-w001, weekly turbine valve cycling; and issuing a lessons learned transmittal to those departments associated with the event.

DATE	TYPE	NARRATIVE
9/24/91	Forced Turb. Spurious	The reactor scrammed on neutron monitoring upscale trips as a result of a pressure/power transient induced by the main turbine valves closing. The root cause of the scram could not be determined. Analysis indicated that a spurious signal in the EHC system either falsely signaled a turbine overspeed condition or created a sudden demand signal to be at zero load. (LER# 9112) LER 374-91012-00 At 0015 hours, on September 24, 1991, with Unit 2 in operational condition one (run) at 100% power (1112 mwe), the reactor scrammed on neutron monitoring (nr) (ig) upscale trips as a result of a pressure/power transient induced by the main turbine valves (eh) (tg) closing. No testing or maintenance was being performed at the time of the event. All other equipment responded as designed. All reactor control rods inserted, the main turbine bypass valves opened, the motor driven reactor feed pump maintained reactor level and safety relief valves (SRVs) s, u, k, and e (nb) (sb) cycled and then reseated. The root cause of the scram has not been determined. An analysis of the sequence of events by General Electric indicates that a spurious signal in the EHC system either falsely signaled a main turbine overspeed condition or created a sudden demand signal to be at zero load. The speed circuits of EHC system were replaced and calibrated. This was also the corrective actions to a similar event that occurred on November 5, 1989. Also, the circuits associated with the #1 3khz oscillator were replaced and calibrated. The speed circuits will be continuously monitored until the next refueling outage. The Mark I EHC system was supplied by general electric. This event is reportable pursuant to the requirements of 10 CFR 50.73 (a) (2) (iv) due to an automatic actuation of the reactor protection system.
10/17/91	Turb. Fail VCCard AtSD	With unit shutdown, instrument and control personnel troubleshooting a main steam low intermediate pressure alarm (reported separately) found the voltage comparitor (vc2a12) (General Electric no VCl502) (piece part to the EHC ICNTRL) in the intermediate valve fast closure logic out of calibration an undetermined amount. This would have prevented the intermediate valves from fast closing on a 5% error between the demanded and actual valve position. Though the system was degraded there was no significant plant effect. The cause of the failure was an out of calibration voltage comparitor (vc2a12). No failure analysis was performed. The voltage comparitor would not calibrate to within plant specification and was replaced like for like. The new voltage comparitor was calibrated per plant procedures to within acceptable limits, returned to service and accepted by operations.
10/29/91	Forced TSI Fail AmplCard	The reactor scrammed on turbine stop valve closure due to the main turbine tripping on #6 bearing high vibration signal. The cause of the scram was a spurious trip from a turbine supervisory system vibration amplifier circuit card. The card was replaced. (LER #9114)
10/29/91	LoadRed TSI TBWD	Load reduction for turbine thrust wear detector work.

DATE	TYPE	NARRATIVE
12/07/91	Forced Turb. Relay Fail	A reactor scram occurred due to a turbine-generator stop valve closure, which was initiated by an EHC system malfunction. The exact cause of the EHC malfunction was not determined, however, the most probable cause was a defective relay actuation. (LER# 9122) With the plant at approximately 90% reactor power, during operations surveillance procedure “weekly turbine valve cycling” the EHC system electronic controller panel 843 gave a false “all valves closed” signal that resulted in a turbine generator stop valve closure. The ability of the electronic controller and the EHC system to provide accurate warning signals was rendered inoperable. The plant experienced an engineered safety feature actuation, specifically an automatic reactor scram. The false all valves closed signal from EHC system electronic controller panel 843 was most probably caused by a normally energized mercury wetted relay k6d27, a piece part of panel 843 in the speed select circuit, which deenergized without cause. The relay board has been sent to an independent lab for destructive root cause failure analysis. Station personnel replaced the relay board containing the suspected faulty relay k6d27 with an identical spare. after successful testing, the EHC system was returned to service. LER 410-91022-00 On December 7, 1991, at 0935 hours, with the reactor mode switch in the run position (mode 1), and the plant operating at approximately 90% rated thermal power (905 mwe), Unit 2 experienced an engineered safety feature actuation. Specifically, an automatic reactor scram occurred caused by a turbine generator stop valve closure, which was initiated by (most probable cause) an EHC system malfunction. The root cause investigation is still underway and has not yet determined the exact cause; however, the most probable cause is a defective relay actuation. The immediate corrective action was to respond to the reactor scram and turbine trip in accordance with plant procedures. A work request was issued to investigate the EHC malfunction, which led to the replacement of the relay board containment the suspected faulty relay.
1/10/92	Forced SB&PR	Shutdown for turbine electrohydraulic control system maintenance and regulator repair.
1/16/92	None SB&PR MSPS Drift Wearout	During normal rounds the operator noticed the main turbine EHC control pressure was oscillating between A and B regulators. This failure resulted in a degraded system with no significant plant effects. Unit 2 was at 97% power at time of discovery. This swapping of regulators caused the EHC oil pressure to constantly vary by ±10 psi and thereby stressing the EHC system. Transmitters 2-ms-MSPS-a and 2-ms-msps-b (piece parts of the EHC controller 2-EHC-xy-644) the main steam pressure oscillator, were tested and found to have instrument drift. Failure was due to normal wear and use. Recalibrated the transmitters per TSM (technical support memo)-92-5010-0106. Returned to service and verified correct operation of turbine EHC system.
1/17/92	LoadRed Turb. LmtCycle	Electrohydraulic control oscillations caused 80% power limit.
2/29/92	Forced Turb.	Turbine stop valve master/slave test circuit failure during turbine stop valve testing caused a turbine stop valve (TSV) to close resulting in a reactor trip. It appeared that the inhibit function in the master/slave circuit, which allowed testing of individual TSVs, had malfunctioned, causing closure signals to be sent to TSVs 1, 3, and 4 when TSV 2 (the valve being tested) closed below the 95% open position. The ensuing reactor water level transient caused actuations of containment isolation, RCIC, reactor building isolation and standby gas treatment. HPCI initiated but did not inject. (LER# 9205)

DATE	TYPE	NARRATIVE
4/15/92	Forced Turb. LVGCard Fail Wearout	The reactor was manually scrammed as a conservative measure due to main turbine bypass valve cycling. Minor reactor pressure oscillations occurred when the turbine control valves repositioned in response to an EHC system speed signal anomaly. The cause of the speed anomaly could not be determined. An analysis of the events indicated that the erratic primary speed signal resulted in the EHC switching from load and pressure control to speed control and back again. The pressure increases and bypass valve cycling were responses to proper EHC control system demand signals. (LER# 9204) Unit 2 in startup following a refueling outage. Operators, performing routine observations, found the backup speed sensor indicating light occasionally flashing at the main turbine control panel. System operation eventually degraded to the point where the main steam bypass and control valves were cycling causing reactor power swings. The reactor was tripped manually. Troubleshooting of the EHC system determined that a defective circuit on a low value gate card (a23) was the cause. The card had degraded due to wearout/aging. This card provides turbine speed and acceleration signals for the EHC system. Troubleshooting and monitoring of the EHC system was performed over a period of several months. The a23 card was replaced like for like. Two operational amplifier cards (a24 and a25) that support the a23 card were also replaced. The system was tested satisfactorily and returned to normal operation. LER 374-92004-00 At 1510 hours, on April 15, 1992, with Unit 2 in operational condition one (run) at 18% power (180 mwe), the reactor was manually scrammed as a conservative measure due to main turbine bypass valve cycling. Minor reactor pressure oscillations occurred when the main turbine control valves repositioned in response to an EHC system speed signal anomaly. All equipment responded as designed. All reactor control rods inserted, three of the main turbine bypass valves and no safety relief valves cycled due to the low power level. The root cause of the speed signal anomaly has not been determined. The manual scram was initiated because of the excessive bypass valve cycling. An analysis of the events by General Electric indicates that the erratic primary speed signal resulted in the EHC system switching from load and pressure control to speed control and back again. The pressure increases and bypass valve cycling were responses to proper EHC control system demand signals. Insufficient operational data was obtained during the event and troubleshooting performed subsequent to the event did not result in a determination of the specific cause of the speed signal anomaly, the speed circuits, as well as the outputs of the low value gate and bypass valve amplifier will be monitored by recorders set to trigger on recurrences of the spurious signal throughout the fuel cycle. This event is reportable pursuant to the requirements of 10 CFR 50.73 (a) (2) (iv) due to a manual actuation of the reactor protection system.
4/30/92	Forced Turb.	Turbine electrohydraulic control repair due to oscillations (during mid-cycle outage).

DATE	TYPE	NARRATIVE
5/20/92	TSI Solenoid Fail Forced	LER 277-92009-00 On 5/20/92, at 2115 hours, during the performance of a routine test (RT) -0-001-408-2 cycling of combined intermediate valves reactor scram occurred when two main turbine combined intermediate valves (CIV) closed simultaneously causing a power load unbalance trip signal. The power load unbalance circuitry caused a main turbine control valve fast closure that resulted in a reactor scram. The cause of the event has been determined to be an unexpected closure of the #2 intercept valve (IV) during testing of the #3 CIV. The investigation was unable to recreate the inadvertent closure of the #2 IV. However, a faulty test solenoid on the #2 OV was discovered that might have been a contributing factor to this event. Following the event, the scram and isolations were reset and the affected systems were restored to normal. Two CIV test logic relays and a circuit board on the test logic were replaced as a preventive measure. The faulty test solenoid will be sent off-site for failure analysis and corrective actions will be reviewed and implemented as appropriate. No actual safety consequences occurred as a result of this event. No previous similar events have been identified.
5/21/92	None SB&PR	Unit 1 was at 75% In the main turbine lower relay control room, both the “A” and “B” pressure regulators on the control panel (1c663) were on simultaneously, according to the control room display. Only one of the pressure regulators should control the distribution of power to the turbine. When the operator presses the “A” button for the “A” regulator to distribute power to the turbine, the “B” regulator should automatically shut off. It failed to do this. Operators who looked into this problem found that both regulators were, indeed, signaling for power to be fed to the turbine. While no function was lost, operation along this channel was degraded. Neither the system nor the plant was affected. The root cause of failure is unknown. The suspected cause is defective circuitry in a logic card on the panel that failed to shut down one of the panels. The piece part logic card was replaced with a new one. Logic card was then calibrated to final tolerance. Regulator “A” was set to on and regulator “B” was set to off. System was placed into service without error.
6/4/92	None Turb. Positioner Adjstmnt	Unit 1 was at 13% power when main turbine intercept valve 4 did not open during a startup of the turbine. Further investigation into this problem revealed that the valve positioning Unit for the main turbine control panel (1c663) was not at the proper setting. Because of this failure, the intercept valve failed to receive a strong enough output command from the control panel logic to open the valve. The train was degraded and the unit's startup was delayed. The root cause of failure is unknown. The suspected cause of failure is out-of-mechanical adjustment of the valve positioning unit. The piece-part valve positioning unit was adjusted and tested satisfactorily under was 27105. The unit was then started.
6/19/92	LoadRed SB&PR MCFL Defect Fail	With the plant in startup and reactor power at 4%, operators attempting to roll up the main turbine received a control room indication that the main turbine tripped from oscillations in the control and bypass valves. Further investigation revealed erratic signals from the EHC system speed control circuit in panel pnl843. The ability of the speed control circuit and the system to control turbine speed was rendered inoperable. The plant was unable to continue with reactor startup. The cause of erratic signals from the speed control circuit in pnl843 was a defective transistor q1 in the maximum combined flow card a63, a piece part of pnl843. It was causing high frequency noise about 50 millivolts in the system. It shouldn’t see more than 2 millivolts. The root cause is unknown but is suspected to be a manufacturing defect. Station personnel replaced the maximum combined flow card a63 in pnl843 with an identical spare. Frequency to voltage converters a18 and a20 were also replaced during troubleshooting. after successful testing, pnl843, the EHC system, and the main turbine were returned to service.

DATE	TYPE	NARRATIVE
7/1/92	LoadRed Turb. Fail FVCard	With the plant in startup, during turbine shell warming, operators could not open the turbine control valves. Further investigation revealed the output of frequency to voltage converter in the EHC system turbine speed control circuit, located in panel 843, was giving a false signal indicating 130% turbine speed. The ability of the frequency to voltage converter and the system to provide accurate turbine speed control and associated indications was rendered inoperable. Turbine shell warming was delayed about 10 hours that delayed plant start up. The cause of false output from the frequency to voltage converter, a piece part of the EHC system turbine speed control circuit, is unknown, but is suspected to be a manufacturing defect in the frequency input lower cutoff chip. Station personnel replaced the frequency to voltage converter circuit board in EHC system turbine speed control circuit, located in panel 843, with an identical spare. After successful testing, the speed control circuit and the electrohyraulic control system were returned to service.
8/27/92	Forced TSI Drift Defect TBWD	A reactor scram occurred as a result of a main turbine trip that was caused by a thrust bearing wear detector signal. During the scram response, both turbine-driven feedwater pumps failed to trip. As a result, the reactor water level increased to a level requiring the MSIVs to be closed. The MSIV closure resulted in the safety/relief valves (SRVs) being used to control reactor pressure. During operation of two SRVs, remote position indication failed to show that the valves closed when demanded. RCIC auto-started due to a level 2 initiation signal caused by a pressure spike, due to the main turbine stop valve closure sensed at the instrument racks containing the level transmitters for the RCIC initiation signal. When reactor level was brought under control, a MSIV isolation high steam flow signal was received when the MSIV was opened with 760 psi differential pressure across the valve due to the operator reading the wrong indicator. The turbine thrust bearing wear detector signal was caused by a shift in the detector set point due to a failure of the manufacturer to build the assembly unit per design. The feedwater pump trip failures were caused by flow blockages in the turbine oil systems due to suspended particulate in the oil. Also, the A feedwater pump disk dump valve spool and the B feedwater pump trip solenoid pilot valve both had bent shafts. The SRVs indication failure was due to failure of the linear variable differential transformers to return to their null position because of fretting induced corrosion between the actuating pin and the guide bushings. (LER# 9212)
11/14/92	None Turb. Solenoid Fail Short	The plant was 100% power when the control room reported the “B” main turbine master trip solenoid failed to operate (close) during a surveillance test. The loss of the master trip solenoid valve resulted in a loss of one channel of the prime mover protection function of the main steam system. There was no significant affect on the operation of the plant. The solenoid coil was shorted and burned. The cause is unknown. The coil was replaced in kind, satisfactorily tested and returned to service. (92-11-70); wo-921114080
11/24/92	AtSD Turb. VCCard Fail Wearout	Unit 1 in refueling. Instrument technicians performing surveillance testing on EHC system found the mercury wetted relay for voltage comparator card a07 operating intermittently. Card vc1a07 supports the EHC loss of primary EHC speed signal and vc1a02 supports the power load unbalance (PLU) circuit. The EHC system was degraded because the PLU turbine generator runback and overspeed trip signals were inoperable. There was no significant effect on overall plant operation. Troubleshooting indicated comparator card vc1a07 relays k1 and k2 were defective due to normal wearout/aging. Comparator card vc1a02 was also suspect. The k1 and k2 relays for comparator card vc1a07 were replaced like for like. Comparator card vc1a02 was also replaced like for like. The circuitry was calibrated and retested satisfactorily. The system was returned to service.

DATE	TYPE	NARRATIVE
11/27/92	Forced TSI P.E. Proc	The turbine tripped on high vibration causing a reactor trip. The causes of this event were vibration recorder alarm configuration and personnel error. Personnel were not aware of increasing levels of turbine vibration resulting from normal load increases because the vibration annunciator was already lit due to high vibration on a feedwater pump turbine. Due to the vibration recorder alarm configuration, high feedwater pump turbine vibration caused the common turbine vibration annunciator to alarm even though each feedwater pump has its own annunciator. Due to personnel error, compensatory action for the lit annunciator was not taken. (LER# 9226) LER 366-92026-00 On November 27, 1992, at 0234 CST, Unit 2 was in the run mode at a power level of 1705 cmwt (70% rated thermal power). At that time, the unit scrammed on turbine stop valve and turbine control valve fast closure due to a main turbine trip on high vibration on the #6 bearing. Reactor water level decreased from 37 inches above instrument zero (195 inches above the top of the active fuel) to its minimum of five inches above instrument zero due to void collapse from the rapid reduction in power. This resulted in another scram signal and a group 2 primary containment isolation system signal on low water level. Level was restored automatically by the reactor feedwater pumps (RFPs). Reactor pressure increased from 968 psig to a peak of about 1,030 psig. The turbine bypass valves opened to reduce and maintain pressure below 920 psig. No safety relief valves lifted nor were any required to lift to reduce or control pressure. The causes of this event were recorder alarm configuration and personnel error. Personnel were not aware of increasing levels of turbine vibration resulting from normal load increases because the vibration annunciator was already lit due to high vibration on an RFP turbine. Due to the vibration recorder alarm configuration, high RFP turbine vibration caused the common turbine vibration annunciator to alarm even though each RFP turbine has its own annunciator. Due to personnel error, compensatory action for the lit annunciator was not taken. Corrective actions include changing the vibration recorder alarm configuration and counseling personnel.
12/21/92	Turb. LmtCycle LoadRed	Load reduction due to turbine control valve oscillation concerns.
12/25/92	Forced TSI AlrmCrd Fail	An automatic scram occurred due to a main turbine trip on a high vibration trip signal. The high vibration signal was caused by a failed alarm card in the turbine vibration control circuitry. (LER# 9225)
12/28/92	AtSD Turb. Relay Fail	LER 333-92053-00 The plant was shutdown and in the cold condition for maintenance, modification and refuel. On December 28, 1992, on to occasions during the reset of the main turbine {ta} trip system {jj} for surveillance testing, a Group I isolation {je} occurred when the main Turbine Stop Valves opened with no condenser vacuum established. Testing revealed the failure of a time delay relay in the turbine EHC system {tg} was the cause. The failed relay gave the EHC logic an incorrect signal that caused the turbine stop valves to open. The primary containment isolation system, which sensed the low condenser vacuum condition, actuated a Group I isolation. The relay was replaced.

DATE	TYPE	NARRATIVE
12/28/92	AtSD Turb. Relay Fail Open	The plant was shut down for refuel and maintenance. While surveillance testing the main turbine a relay in the EHC system failed (open) and caused the main steam stop valves to open. Primary containment isolation activated a Group I isolation as observed by the operators performing the test. The relay is a piece part of the EHC controller. Testing of the EHC control system logic circuit revealed a time delay relay contact in the primary trip logic circuit did not close when deenergized. The failed relay contact allowed the main Turbine Stop Valve to open. The suspected cause is wearout and aging. The relay was replaced, in-kind from stock. it was functioned, tested and returned to service.
12/29/92	LoadRed TBWD TSI	Load reduction to re-null thrust bearing wear detector.
01/01/93	TSI Forced Solenoid Fail	Solenoid valve stuck.
1/02/93	Fail Forced	Maintenance outage to repair EHC problems.

DATE	TYPE	NARRATIVE
1/03/93	Elec Grnd. Forced	The unit was at 69% power when the reactor automatically scrammed on high pressure after a transient in the EHC system occurred coincident with a balance of plant (BOP) battery ground alarm. During the event, RCIC, containment isolation, HVAC, and standby gas treatment systems actuated. The cause of the EHC system transient was not established. The cause of the concurrent BOP battery ground could not be determined. (LER # 9301) Unit 2 was operating at 69% power. The balance of plant (BOP) battery ground alarm annunciated in the main control room and all main Turbine Control Valves cycled closed and subsequently reopened. The reactor shutdown (scram) automatically on high reactor pressure. Immediately following the reactor scram, reactor water level momentarily decreased causing the reactor core isolation cooling (RCIC) system to initiate. The cause of the high reactor pressure condition and the resultant reactor scram was due to a transient in the hydraulic power unit, 20-t117, (HPU). The cause of the HPU transient could not be established. The cause of the concurrent BOP battery ground and any relationship to the HPU transient could not be determined. The root cause of the failure is unknown. Extensive troubleshooting and testing of HPU and bop battery systems was performed by plant engineers and no equipment abnormalities could be identified. No long term corrective actions will be implemented. Monitoring equipment was installed on the HPU to provide information if a similar transient occurs in the future. LER 353-93001-00 On January 3, 1993, the Unit 2 reactor shut down automatically on high pressure after a transient in the EHC system occurred coincident with a balance of plant (BOP) battery ground alarm. Following the reactor scram, reactor water level momentarily decreased to -37. 9 inches causing the reactor core isolation cooling (RCIC) system to initiate, various primary containment and reactor vessel isolation control system (PCRVICS) isolations to occur, and a reactor enclosure secondary containment isolation. These are engineered safety feature (ESF) actuations. The reactor shut down on high pressure as designed, and all control rods fully inserted. The RCIC system initiated but did not inject because the signal was not present long enough to have other injection valve “open” permissives satisfied. The ESF actuations functioned as designed and the affected systems were expeditiously restored, thereby preventing any adverse impact on other plant systems. Following recovery from the scram, Unit 2 entered operational condition 2 (startup) on January 6, 1993, at 2307 hours. The cause of the EHC system transient and coincident BOP battery ground could not be established. While the unit was in operation, monitoring equipment was installed on the EHC system to provide information if a similar transient occurred. Tests on the EHC and BOP battery systems are currently being performed during the Unit 2 refueling outage, which began on January 23, 1993, and any related problems identified will be corrected during this outage.

DATE	TYPE	NARRATIVE
1/17/93	None Turb. Drift PressSwt	LER 249-93002-00 On Unit 3, while performing instrument surveillance (DIS) 5600-3, generator load rejection control valve fast acting solenoid valve pressure switch calibration, three out of four main turbine control valve (TCV) fast acting solenoid valve (FASV) pressure switches (ps) were found to actuate below the minimum set point limit per technical specification table 3.1.1., reactor scram signal to the RPS circuitry upon initiation of fast closure of the TCV. This scram signal is provided in anticipation of the rapid increase in pressure and neutron flux resulting from fast closure of the TCV due to a load rejection. Previous testing has concluded that instrument drift over pressure switch settings in the range of 120–590 psig. Has negligible significance relative to instrument response time to actuate a reactor protection system (RPS) trip. All three of the switches were replaced, all were calibrated, and left to trip within the required set point limits.
1/29/93	LoadRed Turb. CardNS Fail Wearout	Reactor was critical below 20% power with the main steam system and electrohydraulic system in service. while monitoring component operation, operators found the turbine control valves did not open with “100 rpm/slow” selected. This demand failure resulted in a complete loss of function and degraded system operation. This resulted in a power reduction to conduct repairs. The cause of the failure has been attributed to the out of calibration of the EHC electronic controller. The null on a-25 (noun name unknown) was misadjusted (low). This out of calibration was believed to be due to normal wear. The controller was adjusted to within required limits. The component was tested and returned to service.
2/16/93	AtSD Turb. Proc	LER 373-93006-00 On February 16, 1993 Unit 1 was in operational condition 4 (cold shutdown) at 0% power. At 1452 hours a Group I isolation occurred due to the reinstallation of the servo amplifier demodulator indicator (SADI) boards with low condenser vacuum condition, while the main turbine was reset and speed selected for 1,800 rpm. The instrument maintenance department (IMD) was verifying the calibration of the primary speed circuit low valve gate per lip-eh-24. A precaution of this procedure recommends removal of the SADI boards per lip-eh-28 methods of preventing valve movement (EHC system) in order to prevent undesired turbine valve movements. The procedures do not contain information concerning the potential of causing a Group I isolation. Following the completion of lip-eh-24, the turbine is left in a reset condition with 1800 rpm selected and the SADI boards removed. When the SADI boards were installed with a speed selected, the associated turbine valves attempted to open. This resulted in a Group I isolation due to low condenser vacuum with turbine valves not full closed. Normally the EHC calibrations are performed during refuel outages where the Group I isolations are bypassed by operating procedures. The IMD technicians, therefore, do not have to be concerned with generating isolation signals during the calibration. In this case, IMD was performing calibrations during a forced outage in which the isolations were not bypassed. The cause of this event was inadequate directions within the procedure. The appropriate information was not contained in the procedure to ensure the turbine is tripped. The procedure will be revised. This event is reportable as a license event report pursuant to 10 CFR 50.73 (a) (2) (iv) due to an automatic actuation of an engineered safety feature.

DATE	TYPE	NARRATIVE
3/07/93	SB&PR MSPS Design Forced	Inadequate substitute pressure transmitter installed.
3/07/93	TSI Solenoid LoadRed Fail	Load drop for master trip solenoid valve replacement.
3/28/93	LoadRed TSI	Load reduced to 22% due to turbine mechanical overspeed trip test device misaligned test oil injection tubing.
5/1/93	Forced Elec Invrtr Fail	Steam was being admitted to the Unit 2 turbine for chest warming prior to startup when the operators received a “loss of EHC (electrohydraulic control) 125 VDC supply” alarm, a “ground on negative” alarm and noticed the 125 VDC system was experiencing pertubations. The turbine was tripped to avoid a possible reactor trip. The failure delayed the Unit 2 startup by 2 days. Maintenance found the EHC 125 VDC inverter (2-EHC-125vdc-jr5) had no output. The reason for the failure was unknown but was attributed to normal age and wear. Maintenance replaced the 125 VDC inverter (2-EHC-125vdc-jr5), a piece part of the EHC, with an identical spare. The EHC was tested, all alarms were cleared and Unit 2 startup was continued.
5/16/93	Forced Turb. Relay Fail	Failure of an Agastat relay on an EHC control card during weekly turbine overspeed protection surveillance caused the turbine control and intercept valves to close and the turbine bypass valves to open. The reactor tripped from 61% power on high pressure, and the main turbine tripped simultaneously on reverse power protective relay actuation. (LER# 9304) LER 354-93004-00 On 5/16/93 a component failure in the EHC system resulted in a generator/turbine trip and reactor scram on reactor high pressure. The transient occurred while testing the No. 2 Turbine Stop Valve during the weekly turbine overspeed protection surveillance. Operating pressure exceeded 1,037 psig and reactor water level reached -5 inches. Lo-Lo set pressure was reached and P&H safety relief valves (SRV) cycled open once. Plant systems and components responded as expected. The root cause was attributed to a failed Agastat relay on an EHC control card. Corrective actions included troubleshooting and replacement of specific components. The EHC system was monitored and valve testing was repeated successfully during plant startup prior to exceeding 30% power.

DATE	TYPE	NARRATIVE
5/21/93	Forced Turb. P.E. Proc	LER 366-93005-00 On May 21, 1993, at 1939 CDT, Unit 2 was in the run mode at a power level of 1581 cmwt (approximately 65% of rated thermal power). At that time, licensed operations personnel were performing surveillance procedure 34sv-c71-005-2s, Turbine Control Valve fast closure instrument functional test. This procedure tests the rpt logic that causes a trip of the reactor recirculation pumps in the event of a main turbine trip above 30% power. The procedure requires opening a test switch to disable the rpt trip while each main turbine control valve (TCV) is cycled. Per the procedure, the licensed operator should have disabled the a logic using the a test switch. Instead, he mistakenly moved the B test switch, disabling the B logic that was not being tested and leaving the A logic active. Subsequently, when the TCV in the a logic channel was closed per the procedure, the rpt logic was satisfied, and both reactor recirculation pumps tripped per design. Licensed operators immediately inserted a manual scram as required. Reactor water level decreased following the scram as expected, producing a second scram signal and closure of the Group 2 primary containment isolation system valves. Water level was restored from a low point of 161 inches above the top of active fuel by the reactor feedwater pumps. No emergency core cooling systems injected, nor were any required to do so. The cause of this event is a personnel error on the part of a licensed operator. Specifically, he manipulated the wrong test switch while performing a surveillance. Subsequent movement of the TCV being tested completed the logic required to produce a trip of the recirculation pumps. Corrective actions for this event included temporarily removing the involved operator from licensed duties and subjecting him to formal discipline under the company's positive discipline program.
9/24/93	Forced Turb. Grnd. Fail	LER 333-93020-00 On September 24, 1993, at 0709 hours, an automatic reactor scram took place when the main turbine bypass valves partially closed during the conduct of troubleshooting. Due to the potential risk of initiating a turbine trip, reactor power had been reduced, and the main turbine had been taken out of service to support troubleshooting an electrical ground in the turbine EHC system. The plant was at 17.5% power in the run mode with reactor pressure being controlled automatically by the main turbine bypass valves. While lifting individual leads in the main turbine alarm and trip circuit, a partial closure of the turbine bypass valves occurred. The bypass valve partial closure caused reactor pressure to increase and an automatic scram on high reactor pressure. The event was caused by personnel error. Personnel performing the troubleshooting did not adequately verify plant response. The use of electrical drawings that did not adequately support troubleshooting contributed to the event cause. The electrical drawings will be upgraded.

DATE	TYPE	NARRATIVE
9/28/93	AtSD Proc Turb.	LER 325-93012-00 Unit 1 was in a refuel outage. On September 8, 1993, maintenance began an alignment of the EHC system. This alignment required stroking the main turbine control valves. On September 26, 1993, operations shifted to a unit auxiliary transformer (UAT) backfeed line-up that closed the main generator power circuit breakers (pcbs). When the main generator pcbs are closed, an EHC logic circuit automatically selects a turbine speed of 1800 rpm when the main turbine is not tripped. On September 28, 1993, maintenance requested permission from the shift supervisor (SS) to continue with the EHC work. At 0920, the reactor operator reset the main turbine trip, enabling the 1,800 rpm turbine speed select. The turbine stop valves opened in response. This action, in conjunction with a low vacuum condition in the main condenser, generated a Group 1 isolation signal. All systems operated as designed and the main steam drain valves closed. The main steam isolation valves (MSIVs) were already closed. The cause of the event was the lack of administrative barriers in place to prevent the initiation of a Group 1 isolation during the EHC alignment. Steps were not taken to mitigate the effects of using an alternate power source during outages. The UAT backfeed procedure did not adequately address maintenance activities requiring resetting the main turbine trip. Corrective actions include revising the UAT backfeed procedure to provide steps to disable the automatic speed demand feature. The safety significance was minimal. All systems operated as designed. The cause classification for this event per the criteria of nureg-1022 is defective procedure.
10/14/93	AtSD Elec PwrSup Wearout Grnd. Fail	With the plant in refueling, operations personnel detected several alarms with the EHC system including a loss of 125 VDC power supply (1-EHC-125VDC). Operations deenergized portions of the EHC system and notified electrical maintenance of the problem. The loss of the power caused a loss of automatic trip function, however, manual trip was still operable. The failure resulted in degraded system operation due to the loss of 125VDC power but there was no significant effect on overall plant operations due to Unit 1 being in refueling. The failure of the power supply was initiated by a ground on the turbine thrust bearing wear detector motor that resulted in the 125VDC power supply (piece part of the EHC controller) burning up. The power supply had overcurrent protection and should not have failed due to the ground but it failed due to a bad capacitor because of normal age and use. The cause of the ground on the wear detector motor was the insulation on the motor leads were old, cracked, and brittle due to wearout and aging. The turbine bearing wear detector motor was replaced like in kind and the power supply was replaced like in kind. The EHC system was left in satisfactory condition.

DATE	TYPE	NARRATIVE
10/26/93	Forced Connection Turb. Fail Solder	The B control building chiller was in an administrative limiting condition for operation (LCO) and maintenance was being performed on the LPCI system to replace a cooling fan on bay 4 of turbine EHC cabinet 1C049 in the back panel area of the control room. A technician was attempting to disconnect the power leads to the existing cooling fan when an automatic reactor scram from 100% power occurred. A half scram on the turbine control valve fast closure and a half scram on average power range monitor high flux occurred. Following the scram, expected void collapse caused indicated vessel level to drop below low level set point to minimum level. Primary containment isolation system Groups 2-5 occurred. Level then swelled due to reactor feedwater pump injection, causing a feedwater pump trip. The cause of the event was due to a ground fault in EHC cabinet 1C049 that was traced to the fast acting solenoid valve that operates main turbine control valve CV3. A connector to the coil of the solenoid valve had a broken solder joint. That caused the coil of the solenoid valve to be shorted to ground while maintaining circuit continuity. No cause for the broken solder joint was determined, but use and age were suspected. A momentary arc was created by the technician when he touched his pliers to the fan power lead, resulting in a dump of the EHC hydraulic pressure, causing an RPS channel A, half scram and partial closure of valve CV3. The momentary closure of CV3 caused a pressure spike in the reactor that caused reactor power to increase due to void collapse, causing the high flux RPS channel B, half scram. (LER# 9310)
10/28/93	Forced Turb. Solenoid Fail Grnd.	Load reduction to repair turbine supervisory system DC power supply. LER 331-93010-00 On October 26, 1993, with the plant operating at 100% power, a full automatic reactor scram occurred. The scram signals were turbine control valve fast closure and average power range monitor high flux. An unknown ground at a turbine solenoid valve, combined with a momentary arc caused by maintenance on a fan in the EHC cabinet in the control room, resulted in completion of the circuit to close one of the four turbine control valves. All control rods inserted and vessel level dropped below the low level set point causing groups 2–5 primary containment isolations. Vessel level was restored and returned to normal. Reactor pressure was controlled by the turbine bypass valves. There were no emergency core cooling system actuations and no safety relief valve openings. The ground at the turbine solenoid valve was repaired and other turbine valve circuits were checked for grounds but none were found. The reactor was re-started on October 28, 1993.
11/29/93	None Turb. Proc	LER 237-93025-01 During Unit 2 reactor startup on November 29, 1993, reactor mode was changed from startup to run. Technical specification surveillance (dos 500-8, main steam line isolation valve closure scram circuit functional test; dos 500-9, turbine control valve fast closure (load reject) scram circuit functional test; dos 500-10, turbine stop valve closure scram circuit functional test) were not performed until the startup came to a hold point at about 400 mwe. This is consistent with past practice; however, on December 1, 1993, operation's raised a question for interpretation regarding the timeliness of these surveillances. A review indicated that the surveillances should have been performed within the technical specification limiting condition for operation. As a result this LER is being submitted under the requirements of 10 CFR 50.73 (a) (2) (i) (b). Additional reviews have been performed on the startup checklist, startup procedures and additional guidance will be added requiring operators to review over due surveillances against tech specs and to detail the entry point into the tech spec lco.
12/01/93	Turb. Connection Short LoadRed Fail	Unit 1 load drop was taken to repair a shorted wire on Control Valve Pressure switch.

DATE	TYPE	NARRATIVE
12/16/93	Forced Turb. Relay Design Spec	The main turbine tripped from 97% power, causing a reactor scram. Group 1 primary containment isolation was generated due to spurious main steam low pressure signals. That resulted in a MSIV closure. The turbine trip was caused by a main condenser low vacuum signal. However, vacuum was found to be normal. A relay contact for condenser low vacuum trip was found to have failed in the closed position. The relay (C.P. Clare & Co., type mercury-wetted relay, model# HGSM5001) failure was due to manufacturing specifications, with the design analysis as a contributing cause. The relay was replaced. (LER# 9323) LER 254-93023-00 At 2355 hours on December 16, 1993, the Unit 1 main turbine (ta) tripped from 97% reactor core thermal power. The turbine stop valve closure initiated a reactor scram. Spurious main steam line low pressure signals generated a group one primary containment isolation (PCI) (jm). The turbine trip was caused by a main condenser (sg) low vacuum signal, but vacuum was found to be normal. The main steam isolation valves were reopened and a reactor cooldown was started. A relay contact for condenser low vacuum turbine trip was found to have failed in the closed position. The root cause of this event was a relay failure due to manufacturing specification. A contributing cause of this event was design analysis. The relay was replaced like for like and tested satisfactorily. Other trip relays that provide turbine trip signals, but are not routinely tested through periodic surveillance were tested prior to start up. The station is investigating options for improving the reliability and possibly adding redundancy to the turbine trip logic.
12/31/93	Forced Solenoid	EHC system solenoid trouble extends outage.
2/10/94	AtSD Turb. RefCrd Fail Wearout	During a plant startup, personnel were preparing to perform main turbine overspeed testing. The turbine was at approximately 1600 rpm and the turbine tripped prior to beginning the turbine overspeed test. The turbine trip resulted in a loss of system because if Unit 1 was at power the turbine would have tripped prior to actually reaching the overspeed trip set point. There was no effect on unit startup. The cause of the turbine trip was due to the backup overspeed reference voltage being too low due to a failed zener diode (piece part of the controller). The root cause of the failed zener diode was component wear, age and continuous use. The reference voltage should have been 12 volts. The as found voltage was approximately 8.9 volts, which corresponds to 1585 rpm. The defective diode was replaced like in kind and the EHC system was left in satisfactory working condition.

DATE	TYPE	NARRATIVE
3/12/94	Forced MMI Swtch Fail	While at 100% power the unit experienced an automatic reactor scram caused by turbine control valve fast closure and primary containment and reactor vessel isolations caused by low reactor vessel water level. The cause of the event was a faulty push button test switch in the power/load unbalance trip circuit of the turbine EHC system. This caused the power/load unbalance trip circuit to become energized and the turbine control valves to fast close on a power/load unbalance trip signal. (LER# 9401) With the plant at 100% reactor power, operations personnel were performing weekly main turbine power-load unbalance (PLU) circuit testing. When the PLU test push button was depressed the internal switches should operate so that a "break before make" sequence is achieved. The switch contacts operated in a "make before break" sequence allowing the trip test signal to be transmitted to the PLU initiating relays and causing a turbine control valve fast closure. This failure rendered the test circuit inoperable. There was no affect on the normal circuitry. The turbine control valve fast closure caused a turbine trip that resulted in a reactor scram. The cause of the test push-button failure was non-sychronous contact operation of internal switches 1 and 3 that allowed the "make before break" sequence to occur. The test push-button is a piece part of the EHC electronic controller. Contributing causes were the slow and deliberate depression of the push button and probable fatigue in the switch actuation mechanism. Station personnel replaced the test push button with an identical spare. After successful testing the EHC electronic controller was returned to service. LER 410-94001-01 On March 12, 1994 at 1923 hours, Unit 2 experienced several engineered safety feature actuations. Specifically, an automatic reactor scram caused by turbine control valve fast closure and primary containment and reactor vessel isolations caused by low (level 3) reactor vessel water level. At the time of the event, the reactor mode switch was in the run position (operational condition 1) with the plant operating at approximately 100% of rated thermal power. The cause of the event was a faulty push-button test switch in the power/load unbalance trip circuit of the turbine EHC system. This caused the power/load unbalance trip circuit to become energized and subsequently, the turbine control valves to fast close on a power/load unbalance trip signal initiating this event. The root cause of this event is poor equipment design. Corrective actions include replacement of the faulty test switch, a review of similar switches used in similar applications and a review of all safety-related control circuitry for the impact of a similar failure. Changes to the power/load unbalance and the backup overspeed test circuit designs and test frequencies will be evaluated. Additional corrective actions identified will be implemented by the completion of the next refueling outage.

DATE	TYPE	NARRATIVE
3/16/94	None Turb. Solenoid Sticking	With the plant in startup from a previous reactor scram, operators in the main control room were performing weekly surveillance testing on the master trip solenoid b (MTSV-b) valve. After depressing the push button mtsv-b failed to re-position when de-energized. This failure rendered mtsv-b inoperable. There was no affect on the channel or the system because the redundant mtsv-a solenoid was not tripped. It takes two-out-of-two to send a turbine trip signal. Additionally, a mechanical trip is also available to trip the turbine. There was no affect on the plant. The cause of failure is suspected to be a sticking b solenoid valve. The mtsv-b solenoid valve is a piece part of the EHC hydraulic power unit. The suspected root cause is believed to be a varnish substance. The varnish substance is believed to have been deposited on the mechanical portion of the solenoid valve because of a leaking seal in the mtsv that might have allowed EHC fluid to break down the solenoid coil varnish coating thereby allowing it to flow into the solenoid core area. Station personnel replaced the mtsv and the b solenoid. After successful testing the mtsv-b was returned to service.
04/18/94	Forced SB&PR POT Fail Erlylife	Unit 2 reactor scram during startup. Pressure regulator potentiometers need maintenance improvements The reactor automatically scrammed from 15% power when the MSIVs unexpectedly closed. MSIV closure was caused by low main steam pressure when six main turbine bypass valves spuriously opened to their full position. ESF systems responded as designed, including the automatic isolation or actuation of primary containment isolation systems groups. The cause of the bypass valves opening was a defective pressure regulator potentiometer in the EHC circuitry. (LER # 9405) LER 260-94005 On April 18, 1994, at approximately 0355 hours CDST, the Unit 2 reactor automatically scrammed from 15% power when the main stream line isolation valves (MSIVs) unexpectedly closed. MSIV closure was caused by low main steam pressure when six main turbine bypass valves (BPVs) spuriously opened to their full open position. Engineered safety feature (ESF) systems responded as designed. These systems included the automatic isolation or actuation of primary containment isolation system groups 2, 3, 6, and 8. This event is reported in accordance with 10 CFR 50.73 (a) (2) (iv) as an event that resulted in the automatic actuation of any ESF, including the reactor protection system. TVA determined that the most likely cause of the BPVs opening was an EHC system malfunction. A defective pressure regulator potentiometer was found in the EHC circuitry. The defective potentiometer was replaced and satisfactorily tested before the restart of Unit 2. TVA will perform a failure investigation of the defective potentiometer and reevaluate preventive maintenance actions for other sensitive system potentiometers. While there have been a number of previous reactor trips due to EHC/turbine control problems, there were no previous similar reactor scrams caused by multiple BPVs opening unexpectedly.
6/12/94	Fail SB&PR Fan LoadRed	EHC cabinet fan failure caused bypass valves to open. Main turbine control valve oscillations due to EHC electronics problem.

DATE	TYPE	NARRATIVE
8/25/94	Forced Turb. Noise	The unit was operating at 100% power when the main turbine control valves (CV) began to drift closed. In response to this closure, the main turbine bypass valves (BPV) began to open sequentially to control reactor pressure. Approximately 13 seconds after the CVs began to close the BPVs closed, which resulted in an increase in reactor pressure. The increasing pressure collapsed voids in the core that increased moderation and, in turn, caused power to increase. When reactor pressure reached about 1,023 psig, a reactor scram occurred due to reaching the Average Power Range Monitor high flux scram set point. The cause of the CV and BPV movement was due to high frequency noise on three of the cards in the EHC circuitry. A contributing cause was nine cards were not fully seated in their connectors. (LER# 9406) LER 374-94006-00 On August 25, 1994, Unit 2 was in operating condition 1 (run) operating approximately 1118 mwe. At approximately 0328 hours, the main turbine control valves (CV) began to drift closed. In response to this closure, the main turbine bypass valves (BPV) began to open sequentially to control reactor pressure. Approximately 13 seconds after the CVs began to close the BPVs closed, which resulted in an increase in reactor pressure. The increasing pressure collapsed voids in the core that increased moderation and in turn caused power to increase. When reactor pressure reached approximately 1,023 psig, a reactor scram occurred due to reaching the average power range monitor (APRM) hi-flux scram set point. The apparent cause of the CV and BPV movement was due to high frequency noise on three of the cards in the electrohydraulic control circuitry. An additional contributing cause was nine cards were found not fully seated in their connectors. This event is being reported to the nuclear regulatory commission as a licensee event report in accordance with 10 CFR 50.73 (a) (2) (iv) due to an actuation of an engineered safety feature (ESF) and unplanned automatic reactor protection system (RPS) reactor scram.
9/01/94	Turb. LoadRed Valve	A Unit 2 load drop was taken due to #2 Stop Valve problem.

DATE	TYPE	NARRATIVE
10/07/94	Forced Turb. CardNS	With a reactor startup in progress, operators were preparing to roll the main turbine. The reactor was operating at 15% power with six turbine bypass valves open. The Nuclear Control Operator (NCO) had selected the 100 RPM speed demand at the EHC panel that should have brought the turbine to the selected speed. The NCO observed that all the turbine bypass valves had closed. Control room personnel noted that turbine speed had exceeded the 100 RPM selected speed and was accelerating rapidly. The Shift Supervisor directed the NCO to trip the main turbine. The NCO recommended to shutdown the turbine by selecting ALL VALVES CLOSED. When the turbine ALL VALVES CLOSED was selected and the valves began to close, a reactor scram occurred. The root cause of this event was a failed card in the EHC control circuit. A contributing factor was operators not recognizing the abnormal plant conditions indicated on the EHC panel when the turbine was reset prior to initiating the turbine roll. (LER# 9415) LER 354-94015-00 On Friday, October 7, 1994, with a reactor startup in progress, operators were preparing to roll the main turbine generator. The reactor was operating at approximately 15% of rated with 6 turbine bypass valves open. The nuclear control operator (nc0-ro licensed) had selected the 100 rpm speed demand at the EHC system panel that should have brought the turbine to the selected speed. The NCO monitoring the turbine roll initially observed normal responses from the turbine stop valves (TSVs) position indicators, the all valves closed light extinguishing and the speed increasing' light illuminating. The operator then observed that all turbine bypass valves had closed. This unexpected response was immediately recognized and communicated to other control room personnel by both the NCO and shift technical advisor (sta-sro licensed). Control room personnel concurrently noted turbine speed had exceeded the 100 rpm selected speed and was accelerating rapidly. The nuclear shift supervisor (nss-sro licensed) directed the NCO to trip the main turbine. The NCO recommended to shut down the turbine by selecting all valves closed. When the turbine all valves closed was selected and the valves began to close, a reactor scram occurred. The root cause of this event was attributed to failed components in the EHC control circuit. A contributing factor was operators not recognizing the abnormal plant conditions indicated on EHC panel when the turbine was reset prior to initiating the turbine roll. Corrective actions included replacement of the EHC card, revising the turbine roll procedures and expanding operator training to include actions to be taken when abnormal plant responses are noted.

DATE	TYPE	NARRATIVE
10/19/94	Forced Turb. Fail Connection Intrmtnt	While operating at 100% power, turbine control valve oscillations were observed. Plant personnel were unable to immediately determine the cause of the oscillations and as a result, EHC piping, which was subjected to the same oscillations, began to leak. The piping eventually broke due to low cycle fatigue. A main turbine trip occurred due to the loss of EHC fluid pressure and the reactor scrammed on high neutron flux when the turbine control valves closed. The root cause for the control valve oscillations was due to a faulty connector on the EHC permanent magnet generator (PMG) 30VDC power supply. The faulty connector allowed the 30VDC power to cycle between the house supplied power supply and the PMG power supply. (LER# 9408) LER 374-94008-00 On October 19, 1994, Unit 2 was in operational condition 1 (run). Turbine control valve oscillations were first observed at 1015 hours. Plant personnel were unable to immediately determine the cause of the oscillations and as a result, turbine electrohydraulic control (EHC, eh) {tg} piping, which was subjected to the same oscillations hydraulically, began to leak. The piping eventually broke due to low cycle fatigue. A main turbine trip occurred due to the loss of EHC fluid pressure, and the reactor scrammed on high neutron flux when the turbine control valves closed. Reactor core isolation cooling (RCIC, ri) {bn} and anticipated transient without scram-recirc pump trip/alternate rod insertion (atws-rpt/ari) initiated on spurious low reactor water level (level 2, -50) signals. Six safety relief valves (SRVs) opened sequentially following the turbine trip. The required notifications were made, and troubleshooting and investigation were initiated. An investigation was performed, and the root cause for the EHC control valve oscillations was due to a faulty connector on the EHC permanent magnet generator (PMG) 30 VDC power supply. The faulty connector allowed the 30 VDC power to cycle between the house supplied power supply and the PMG power supply. EHC piping and the electrical connector were repaired and an extensive inspection of EHC piping was completed prior to starting up Unit 2.
01/01/95	None SB&PR	Main turbine bypass valve #1 was observed to be “bouncing” from the closed position to about 25% open position.
01/01/95	None MMI Fail Indctr Wearout	During weekly turbine generator testing per 2-OI-47 section 6.4 master trip solenoid a backlight (2-HS-47-67c) did not re-illuminate. Fix was to replace light bulbs.
01/01/95	None Proc Elec Relay Instltn	Excessive arcing was observed coming from the x relay of 3B EHC pump brakes as it was put into service. Wires on x relay that were feeding closing coils and y relay were rolled.
01/01/95	None SB&PR	Unit 2 main steam pressure regulator “A” began oscillating from 900 to 1000 psig with the “B” regulator in control on 7/24/95 at approximate 2300 hours. No effect was observed on pressure control because the “B” regulator was in control and the “A” regulator pressure never exceeded the “B” signal (regulators did not swap). Due to concerns about the possibility of swapping, the A52 modulator card in the U2 aux. instr rm. EHC panel was removed to fail the “A” regulator downscale to prevent swapping.

DATE	TYPE	NARRATIVE
01/01/95	None SB&PR Drift ILNcnds	Unit 2 EHC pressure regulators "A" and "B" were observed to be swapping. The "B" regulator was in control when the "B" pressure increased approximately 2 psi and took control. Fix was to widen bias and backfill sense lines.
7/13/95	Forced SB&PR Fail	The unit scrammed from 100% power when reactor pressure perturbations caused by a malfunctioning EHC pressure regulator created reactor power fluctuations. The automatic isolation and/or actuation of PCIS groups 1, 2, 3, 6, and 8 occurred as designed. With the reactor stable and scram signals reset, a full RPS actuation and the expected ESF actuations occurred due to momentary shrink in reactor water level below the low level #1 set point. The second event occurred following the cycling of a safety/relief valve that was being used to control reactor pressure. The specific component failure causing the malfunction of the EHC pressure regulator had not been determined and was being investigated; however, the failure mechanism was localized to the four circuit boards that comprise the A pressure regulator circuitry. The four A pressure regulator circuit boards were replaced and satisfactorily tested before restart. (LER# 9515) While operating at power, a scram on Unit 1 was received due to problems with the EHC system. It appeared that the pressure regulator a (piece part of the EHC controller panel) attempted to fail downscale approximately 3–4 minutes prior to the scram and then failed up at 28 psi and an error signal was received and the a regulator took control of the Control Valves and bypass valves and the unit scramed. Further investigation revealed a problem with some of the cards contained within the EHC control panel. The root cause of the failure is still under investigation and the 4 cards that were replaced are being sent to GE for failure analysis. When a root cause has been determined, this failure will be updated. Four circuit cards were replaced like in kind the EHC system was tested and returned to normal operating condition and the unit was returned to 100% power. LER 95-015 LER 325-95015-01 On July 13, 1995, at 1158 hours, the Unit 1 reactor automatically shutdown (scram) from 100% power when reactor pressure perturbations caused by a malfunctioning EHC pressure regulator created reactor power fluctuations. Average power range monitors e and f generated a full reactor protection system (RPS) trip as a result of the fluctuating reactor power. The automatic isolation and/or actuation of the primary containment isolation system groups 1, 2, 3, 6, and 8 occurred as designed. With the reactor stable and scram signals reset, a full RPS actuation and the expected engineered safety feature (ESF) actuations occurred on Unit 1 at 1433 hours due to a momentary shrink in reactor water level below the low level 1 set point. The EHC malfunction was localized to four pressure regulator a circuit boards. The cause of the component malfunction is still indeterminate following failure mode testing by General Electric Co. The second event occurred following the cycling of a safety relief valve that was being used to control reactor pressure. Prior to Unit 1 startup with the reactor in hot shutdown, two additional full RPS logic actuations and expected ESF actuations occurred on July 14, 1995, at 2254 hours, and on July 15, 1995, at 0425 hours, when a momentary perturbation of the reactor water low level channels a2/b2 instrument sensing lines resulted in an invalid low level 1 trip signal. The momentary perturbations resulted from pressure spikes on the b reference leg sensing line that occurred when actual reactor water level was being lowered to a point below the reactor pressure vessel reference leg nozzle.
07/13/95	Turb. Fail LoadRed LimitSwt Water	CIV closure due to limit switch full of water.

DATE	TYPE	NARRATIVE
8/20/95	Turb. Relay Fail Forced HiOhm	An automatic reactor scram from 100% power occurred due to a high reactor vessel pressure signal resulting from main turbine control valve closures. Subsequent to the reactor scram the main turbine tripped on high reactor pressure vessel water level. The cause of the turbine valve oscillations was concluded to be high impedance across the normally closed contacts of relay KT106, causing an energized relay coil downstream of the KT106 relay to drop out momentarily. (LER # 9510) LER 353-95010-00 On 08/20/95, an automatic Unit 2 reactor scram occurred, a reactor protection system actuation, from a high reactor vessel pressure signal resulting from main turbine control valve closures. Subsequent to the reactor scram the main turbine tripped on high reactor pressure vessel (RPV) water level. Following the main turbine trip, the rapid pressure change from the turbine stop valve closure resulted in a pressure wave traveling through the RPV causing a ringing in the wide range RPV water level instrumentation. This caused various engineered safety feature actuations to occur. The RPS functioned as designed by automatically shutting down the reactor on high RPV pressure. The RPV water level ringing and the resultant instrumentation spike were consistent with the results of previous events. The cause of the turbine valve oscillations was concluded to be high impedance across the normally closed (NC) contacts of relay kt106 (Agastat TDPU, model 2112-d-h116ye), causing an energized relay coil downstream of the kt106 relay to drop out momentarily. The kt106 relay boards for the Units 1 and 2 EHC systems were replaced, modifications were made to wire the spare sets of NC contacts in parallel with the original contacts, and preventative maintenance for the kt106 relay boards will be evaluated.
08/25/95	TSI Fail LimitSwt Forced	Control valve limit switch failure.
8/25/95	Forced SB&PR Design Proc	The unit experienced an automatic reactor scram from 60% power during an EHC pressure regulator fail-over test. Partial closure of the turbine control valves sent a rapid pressure increase to the reactor that caused a scram on high-high APRM flux. The cause of the event was attributed to the failure of General Electric personnel to recognize that a pressure regulator failure would be a worse reactor transient than a 10 psig pressure step change. Inadequate EHC system pressure regulator set point bias and small lag time constant settings were also contributors to the scram. (LER# 9505) LER 265-95005-00 On august 25, 1995, Unit 2 was operating at 60% of rated core thermal power. At 0848 hours, Unit 2 experienced an automatic reactor ?rct? Scram during an EHC pressure regulator ?rg? Fail-over test. The apparent cause of the event was attributed to the failure of General Electric (GE) personnel to recognize that a pressure regulator failure would be a worse reactor transient than a 10 psig pressure step change at the station. Inadequate EHC system pressure regulator set point bias and small lag time constant settings were also contributors to the scram. Corrective actions that have been completed include: adjustment of the EHC system pressure set point bias and time lag constants to obtain a smooth output curve that represents a small transient on the system when a pressure regulator fails. Corrective actions to be completed include: revisions to the EHC lineup instructions for setting up the 3 psig effective pressure set point bias and inclusion of the correct minor lag time constant on the steam line resonance compensator circuit boards. Ler265\95\005. Wpf

DATE	TYPE	NARRATIVE
11/21/95	AtSD Gen Proc	At 1618 on 11/21/95 Unit 3 experienced EHC control system perturbations. The turbine bypass valves closed, they were subsequently controlled on the bypass valve jack. Reactor pressure and level were controlled manually and the main turbine rolled off the turning gear. The problem has been attributed to closing generator breaker 234 while the turbine is in reset. The bypass valve closure is an expected response. Corrective action to clarify procedure.
12/01/95	None Solenoid TSI Fail	During testing of master trip solenoid "A" on U-2's main turbine the plunger on the solenoid stuck in the tripped position and had to be manually reset locally. As corrective action the unit was troubleshot and replaced.
12/02/95	TSI Grnd. Fail Forced	An unexpected main turbine trip occurred and caused closure of the turbine stop valves that initiated a full reactor scram. Immediately following the scram, PCIS Group 2/3 isolations occurred as expected. Troubleshooting revealed that the Mechanical Trip Solenoid Valve's coil was momentarily energized due to a combination of two grounds in the DC electrical power system. The first was an intermittent ground on a terminal strip associated with the Mechanical Trip Solenoid. The second was a momentary ground induced during performance of a routine test. This ground occurred during the installation of grounded test equipment onto a relay contact. (LER # 9507)
1/01/96	None Turb. Proc	During the performance of 2-SI-4.1.A-12 turbine control valve fast closure, or turbine trip and RPT initiate logic testing approximately four bypass valves opened when the number one control valve (CV-1) was being closed. Opening of the bypass valves was not an expected response. The closure signal was removed from the control valve and the bypass valves closed. Opening of the bypass valves has been attributed to the setting of the load limit.
1/01/96	None Turb. LVDT Proc	Unit 3 control valve #3 position indicator on panel 3-9-7 failed downscale. The three remaining CVs closed down 10% to 12% each. The LVDT position indicator connector rod was found dropped out of the valve housing. CV #3 was verified open, work request written to correct problem, and procedure revised to inspect connector rod upon reassembly of control valve spring housing.

DATE	TYPE	NARRATIVE
2/29/96	Forced Turb. FVCard Fail	A failed turbine speed feedback card in the EHC system caused fluctuations in the turbine control and bypass valves. This caused a reactor pressure spike, which, in turn, caused an Average Power Range Monitor high flux spike that scrammed the reactor from 100% power. (LER # 9601) Unit 3 was operating at 99. 9% power when the reactor scrammed after receiving a high APRM neutron flux alarm. The reactor scram followed a pressure transient when the output of the EHC frequency/voltage converter card (piece part of power unit) associated with the speed control drifted to a setting that created a demand to ramp down the turbine control valves. These conditions resulted in engineered safety feature (ESF) actuations. The system channel was inoperable. The failure was due to an unexpected and random equipment failure of the turbine speed control EHC voltage card (piece part). The card simulated a turbine overspeed condition and created a demand signal to ramp down the Control Valves. The increase of reactor pressure resulted in an automatic scram after a high reactor flux alarm was received. The faulty card was replaced and the replacement card was successfully tested. The EHC circuitry was reverified for proper operation and returned to service per plant instructions. LER 296/96001 LER 296-96001-00 On February 29, 1996, at 0158 hours, Unit 3 was operating at 99.9% power and Unit 2 at approximately 94% power when the Unit 3 reactor scrammed after receiving a high APRM neutron flux signal. The reactor scram followed a pressure transient when the output of the EHC frequency/voltage converter (F/VC) card associated with the speed control drifted to a setting that created a demand to ramp down the turbine control valves. These conditions resulted in engineered safety feature (ESF) actuations. Therefore, this event is reportable pursuant to 10 CFR 50.73 (a) (2) (iv), as any event or condition that resulted in manual or automatic actuation of any ESF including the reactor protection system. The cause of this event resulted from a faulty turbine speed control EHC F/VC card. The immediate corrective action was to bring the reactor to a stable condition. The faulty card was replaced. TVA plans to send the faulty card to the vendor for further investigation. Any additional corrective actions that are developed as a result of the vendors investigation will be implemented in accordance with TVAs corrective action process. There was a previous LER (260/94005) that resulted from an EHC system malfunction; however, corrective actions taken in LER 260/94005 would not have precluded this event.
3/09/96	SB&PR MSPS Drift	On 03/09/96, at approximately 2045 hours, while Unit 3 was performing 3-SI-4.1.a-15(1), turbine stop valve closure (RPS) and RPT trip functional, during the testing of the #3 and #4 Stop Valves, the #1 and #2 bypass valves were observed to open and reclose. The load set point was at 100%. Apparent cause was transducer response/calibration.
3/23/96	Forced Turb. P.E. Proc	While shutting down for refueling, the reactor tripped on high pressure after the turbine was taken off-line due to operator error. (LER# 9604)
3/31/96	Turb. SpdCntrlr Fail Forced	Unit 1 load drop was due to 7 bypass valves opening and then closing almost immediately. The most likely cause of the event was identified to be a sporadic anomaly in the function of the primary or backup speed control LVG. The turbine was taken off-line to replace both cards. (This event reoccurred on 7/25/96) The turbine was taken off-line for EHC speed controller card replacement.

DATE	TYPE	NARRATIVE
4/01/96	TSI Swtch Design Short	During the performance of weekly turbine checks, the master trip solenoid test push-button stuck in the "depressed" position. When the button was released, the reset light did not illuminate, thus testing could not be continued. Investigation revealed that the MTS was reset. When the push button sticks, it also blows the light bulbs and causes an alarm "malfunction bus energized." This indicates a short in the turbine control bus, therefore jeopardizing future testing. Corrective action was to replace the hand switch and evaluate it for generic implications.
4/01/96	TSI Design	Operating instruction 2-0I-47 turbine generator system does not include the 2-second time delay in illustration 8, turbine trips as added to turbine high vibration trip per DCN t36762. Corrective action was to revise procedure.
4/01/96	TSI Design	DCN T36726A installed a time delay relay in the turbine generator vibration trip circuit. General Electric (GE) design input for this DCN indicated a delay of 2.0 seconds maximum. The set point was established at 2.0 seconds ± 0.2 seconds, which could result in a maximum time of 2.2 seconds. Corrective action was to get revised design input form GE to allow setting tolerance.
4/01/96	None TSI Proc	During pre-job review for a U2C8 outage activity , it was discovered that SII-2-xx-47-204, "electrohydraulic control system electrical alarm and trip unit calibration and functional test," contained incorrect references to Unit 3, which would have tripped the operating unit. Corrective action was to revise the procedure.
4/01/96	None Drift SB&PR Tmptur	The Unit 3 EHC logic cabinets in aux. inst. room appear to be very sensitive to temperature changes. When a U3 control bay chiller trips, EHC parameters change slightly (probably pressure control unit) causing reactor pressure to change about 2 to 3 psig. Corrective action was to disable "B" loop pressure controller until cards could be replaced in outage.
4/01/96	None MMI Design	The unit operator does not have adequate indication of a change in EHC system controlling pressure regulator status. There is a history on both Units 2 and 3 of controlling regulator swaps without any obvious alarms or indications. Regulator status indicating lights 3-ZI-1-16B on panel 9-7 should be upgraded to brighter lights. An alarm associated with a controlling regulator swap would help. Corrective action was to change indicating lights lens colors.
5/02/96	TSI Relay Fail Forced	The turbine was tripped to replace a backup overspeed relay.
5/10/96	Elec Fail LoadRed Connection	Loose Wire in CV Junction Box
6/07/96	LoadRed Elec PwrSup Fail	Load reduction to 20% to replace an EHC power supply.
6/23/96	Turb. Forced Fail Valve Instltn	#2 Control Valve stem severed from crosshead due to improper clearance between the stem and crosshead.

DATE	TYPE	NARRATIVE
7/25/96	Turb. FVCard Fail Forced	On July 25, 1996, at 0224, the unit experienced a power transient due to a sudden momentary opening of main turbine bypass valves and partial closure of the Control Valves. indicated APRM neutron flux increased to 113.75% over a 10-second period. Analysis indicated that actual peak heat flux was 107.5%. This event was bounded by the licensing basis of the core. In addition, at 0242, an automatic reactor scram occurred on high neutron flux caused by a loss of FW heating due to the isolation of various FW heaters following recovery from the power excursion. The cause of the power excursion was a malfunction of the primary speed frequency/voltage converter in the main turbine EHC system. The cause of the reactor scram was less than adequate procedural guidance regarding power reduction in response to reactivity insertion resulting from the loss of FW heating. (LER # 9616) LER 352-96016-00 on 07/25/96, at 0224 hours, Unit 1 experienced a power transient due to a sudden momentary opening of main turbine by-pass valves and partial closure of the Control Valves. Indicated APRM neutron flux increased to 113. 75% over a 10-second period. Analysis indicates that actual peak heat flux was 107. 5%. This event was bounded by the licensing basis of the core. in addition, at 0242 hours, an automatic reactor scram occurred on high neutron flux caused by a loss of feedwater heating due to the isolation of various feedwater heaters following recovery from the power excursion. The plant responded as designed to the high neutron flux signals. The cause of the power excursion was a malfunction of the primary speed frequency/voltage (f/v) converter in the main turbine EHC system. The defective primary speed f/v converter was replaced. The cause of the reactor scram was less than adequate procedural guidance regarding power reduction in response to reactivity insertion resulting from the loss of feedwater heating. The emergency operating procedure was revised to provide an appropriate target power level on the loss of a feedwater heater string.
8/01/96	Forced TSI TurbVib Spurious	With the unit operating at 98% power, a reactor scram occurred when the main turbine tripped on indicated high vibration, followed by a reactor trip. The cause of the turbine trip was attributed to a false, spurious signal from the turbine #1 bearing vibration instrument loop. The investigation also concluded that the response to some precursor alarms, which might have precluded the turbine trip, was less than adequate. The components of the #1 bearing vibration monitoring loop that most likely could have caused the false signal were replaced. (LER# 9606)
8/26/96	SB&PR MSPS Fail	On 8-26-96 at 1654 hours, the 3B EHC pressure regulator was discovered to be failed downscale. Review of ICS data shows that the failure occurred on 8-24-96 from 1811 to 1814 hours. Corrective action wad to troubleshoot and repair defective transducer.
8/30/96	Turb. Proc Indctr	On 8-30-96 operations was performing weekly turbine testing per 0-OI-47 section 6.9. Step 6.9.7.1. The normal light did not remain illuminated after the testing as required. Note in procedure refers to GEK-17937...GEK-5584 vol. III, tab 43. This vendor manual is not available to operations in the office or in document control (office bldg.). Manual is necessary for troubleshooting EHC controls and needs to be available to ops and on shift tech support. Corrective action is to train operators in vendor manual cross-reference documentation.
11/04/96	None	On 11-4-96, the pressure regulator on Unit 3 swapped to the B regulator at 2210. No system perturbations were observed. At 2334, the pressure regulator swapped again back to the A regulator. Again no system perturbations were observed.
1/08/97	Turb. LoadRed Valve Fail	#6 CIV Bindingdue to bushing failure.

APPENDIX B
EVENTS FOR PWR PLANTS WITH MARK I EHC

DATE	TYPE	NARRATIVE
4/25/84	Forced P.E. TBWD Proc TSI	The reactor tripped from 100% power as a result of a turbine trip. The trip occurred as the main turbine thrust bearing wear detector was being returned to service following a modification. The cause of this event was personnel error. The technician did not adequately review the system status prior to performing the work. Following the trip, FW regulating valves A and B did not automatically close upon the reactor trip coincident with low T_{avg}. The valves failed to close due to one of the air bleedoff valves on each valve being improperly adjusted. (LER# 8425)
4/29/85	Forced Turb. LdDecCrd Fail	A reactor trip occurred at 30% power during a plant shutdown. The reactor trip was initiated by a Low-Low SG level in SG-B. This condition resulted from transients in deaerator tank level and main FW pump discharge pressure, which occurred during the down power ramp. These transients caused a FW isolation on a low FW temperature and low FW flow condition. The FW transients were due to two failures. First, the load decrease circuitry for the main turbine failed to function properly, which resulted in a load reduction of 12% in less than three minutes. This condition was further complicated by a failure of the steam dump system to properly respond to the transient. The load decrease circuit board for the EHC system was replaced. Due to a previous SG tube leak, the transient prior to the reactor trip resulted in an unmonitored release to the atmosphere from the main steam system. (LER# 8513)
2/03/86	Forced Turb.	During a main turbine roll-up, a reactor trip and safety injection occurred from 7% power. The reactor trip and safety injection were a result of a steam line low pressure signal generated during the turbine roll-up. At 400 rpm, the turbine control system experienced an undetermined malfunction which caused a rapid increase in turbine speed to about 1,000 rpm. This rapid increase in speed resulted in a steam flow increase and a rapid decrease in steam header pressure. Following the safety injection, the B component cooling water pump did not automatically start due to an improper breaker alignment. (LER# 8603)
5/28/86	Forced TSI TBWD Drift	A turbine/reactor trip occurred from 90% power due to an apparent overspeed of the main turbine. All ESF responded as designed, no safety systems were activated other than the reactor trip sequence; however, the source range nuclear instrument failed to reinstate as designed. Monitoring instrumentation indicated the overspeed signal originated in the electronic backup overspeed trip circuitry; however, it was determined there was no actual overspeed of the turbine, and the trip actuation was considered a spurious event. The failed component which caused the abnormal response of the source range nuclear instrument was replaced. (LER# 8612)
7/27/86	Forced Turb. PressSwt Noise Intrmtnt	The plant was operating at 90% power when a reactor trip occurred. Power had been reduced so that the monthly test of the turbine control valves (CVs) could be accomplished. During the test of CV-4, a reactor trip was initiated. The cause of the reactor trip was due to the spurious operation of one of the two other CV pressure switches coincident with the test of CV-4 which completed the 2-of-3 logic. The spurious actuation of the second CV pressure switch was due to the induced vibration caused by closing CV-4. (LER# 8614)
11/22/86	Forced	With the unit at 90% power, a turbine/reactor trip occurred. The trip took place during testing of the #4 main turbine control valve and was initiated by an erroneous signal from the main turbine thrust bearing wear detector. The false signal was due to the adjustment of the thrust bearing wear detector drifting to the point where turbine shaft displacement of about 10 mils would generate a trip signal. (LER# 8623)

DATE	TYPE	NARRATIVE
9/9/87	Forced Turb. Positioner Fail	LER 368-87007-00 On 9-9-87, with the unit operating at full power, a reactor trip on high reactor coolant system (RCS) pressure occurred. Failure of an aluminum setscrew-type terminal lug, connecting one phase of the secondary side of a step down transformer to an instrumentation distribution panel, created a partial loss of power to the main turbine electrohydraulic control system, resulting in rapid closure of the turbine control valves. The resulting primary to secondary power mismatch caused RCS pressure to increase rapidly to the reactor protection system trip set point. Emergency feedwater actuated as designed to restore and maintain steam generator water levels. Two turbine bypass valves failed to respond properly during the transient due to failure of positioners associated with their actuators. The cause of the terminal lug failure was electrical arcing between the lug and cable conductors as a result of poor electrical contact due to loosening of the lug around the conductors. The failed log was replaced and the system returned to service after testing to verify a good connection in the repaired area and at other locations with similar connections. The turbine bypass valves were repaired, tested and returned to service. The aluminum setscrew-type lugs on the transformer will be replaced with copper-crimped-type lugs during the next refueling outage.
2/03/89	Forced Elec Prgrm	Loss of 125 VDC power to the EHC system tripped the main turbine, resulting in an anticipatory reactor trip from 100% power. The loss of power was due to a combination of incorrect wiring of a circuit during implementation of a nuclear station modification (NSM) and a preexisting ground on a conductor supplying power from the EHC to the 2A2 moisture separator reheater (MSR) high water level switch. The root causes of the event were: a management deficiency of not properly implementing the independent verification program and of assigning an unqualified technician to perform a task; and failure of wiring insulation on the 2A2 MSR due to vibration against a bracket in the switch housing. A contributing cause was that the QA inspector failed to perform steps which would have identified the miswiring. The main steam relief valves and integrated control system responded properly to the trip, and the unit stabilized at hot shutdown. (LER# 8902) LER 270-89002-00 On February 3, 1989, at 1545 hours, while operating at 100% reactor power, the Unit 2 main turbine (MT) tripped, resulting in an anticipatory reactor trip. The MT trip initiated by a loss of 125 VDC power to the electrohydraulic control (EHC) system. The loss of DC power occurred due to the incorrect wiring of a circuit during implementation of a nuclear station modification (NSM). This, combined with a preexisting ground on a conductor supplying power from the EHC to the 2a2 moisture separator reheater high water level switch, caused a loss of 125 VDC power to the EHC. The immediate corrective action was to stabilize the unit at hot shutdown. Supplemental corrective actions included determining the cause of the trip, correcting the wiring problem, and repairing the degraded conductor. The root causes of this trip were: a management deficiency of not properly implementing the independent verification program and of assigning an unqualified person to perform a task; and an equipment failure.
2/05/89	Forced Turb.	During performance of the secondary systems protection test, just after the master trip solenoid test lever was placed in the trip A position, the main turbine spuriously tripped, resulting in an anticipatory reactor trip. No cause could be identified. The integrated control system responded properly after the trip, and the unit was stabilized in hot shutdown. (LER# 8903)

DATE	TYPE	NARRATIVE
4/18/89	Forced Turb. Xtrctnline Corrosion Fail	Erosion-corrosion caused extensive thinning, plastic yielding, and ultimate catastrophic failure of a high pressure turbine extraction steam line just downstream from the nozzle out of the turbine casing. As a result of the heat released from the ruptured steam line, the fire alarms activated, and the sprinklers deluged on the turbine generator bearings. The control circuits for the main turbine, located nearby, shorted out, causing the turbine generator to trip. The reactor tripped from 100% power as a result of high RCS pressure due to the loss of the secondary heat sink. The turbine-driven emergency FW (EFW) pump started in response to the trip, but soon tripped itself on overspeed. The turbine had accelerated too fast because the ramp time in the governor ramp generator signal converter had drifted from 15 sec to 3 sec. The reactor trip override (RTO) signal in the main FW control system also malfunctioned after the trip, resulting in an overfeed of the A-SG. The insulation of a wire associated with the A-RTO seal-in relays had been damaged during installation and degradation over time led to the wire shorting to ground. One of the two downstream atmospheric steam dump valves (ASDV) failed to open in automatic and manual modes because a galled plug caused the valve to bind. One of the upstream ASDVs failed open (no known reason), causing a slight RCS cooldown and SG depressurization. The plant was stabilized in Mode 3 and subsequently taken to Mode 5. A contributing cause to the steam line break was a slight mismatch in the piping inside diameter and extraction nozzle inside diameter at the point of the weld joining the two components. (LER# 8906)
7/11/89	Forced Turb. Relay Fail	The unit was operating at 100% power when technicians working inside the generator stator cooling water cabinet inadvertently shorted leads on the temperature converter, causing the AC power fuse to blow. This gave a false indication of loss of generator stator cooling water, which led to a turbine trip and a reactor trip due to turbine trip over 50% power. No reactor trip would have occurred had the turbine runback relay not failed (no reason given). Three other generating stations tripped while attempting to compensate for the VARs lost on the grid with the turbine/reactor trip, which caused the off-site voltage to the engineering safety feature buses to fall below the minimum acceptable value. Both DGs started and loaded. All plant systems operated as designed, with the exception of the turbine runback relay. (LER# 8912)
8/18/89	Forced Elec Water Proc	A false EHC system low hydraulic pressure trip signal caused an anticipatory reactor trip from 100% power. Plant response to the trip was normal, and the unit stabilized at hot shutdown. Because the latch on the EHC cabinet door was broken, so that the door was inadequately shut, and because the floor around the cabinet had recently been washed twice using a high pressure service water hose, it was concluded that moisture droplets inside the cabinet had made momentary contact across the terminal strip. Thus, the root cause of the spurious signal was judged to be inappropriate action, poor work practice. (LER# 8904) LER 287-89004-00 On August 18, 1989, at 1233 hours, Unit 3 tripped from 100% full power. The reactor trip was an anticipatory trip, resulting from a false electrohydraulic control (EHC) system low hydraulic pressure trip signal. The false signal was generated when water drops made momentary contact across the terminal strip associated with the low hydraulic pressure trip circuit. The station janitorial service vendor and operations personnel had washed the floor around the EHC hydraulic power unit cabinet prior to the unit trip. The cabinet door was inadequately shut, potentially allowing moisture to enter the hydraulic power unit cabinet. Plant response to the trip was normal, with no radiological releases or engineered safeguard actuations. The root cause of this incident is classified as an inappropriate action, poor work practice. Immediate corrective actions were to stabilize the unit at hot shutdown conditions.

DATE	TYPE	NARRATIVE
12/02/89	Forced Relay Turb. Spec Fail	Prior to this event, the unit had undergone a load reduction from 100% to 90% power for turbine control valve testing. When the operator pressed the button for the next 2% decrease, a turbine control circuit card failed, initiating a rapid load decrease. After manual controls failed to respond, the turbine was manually tripped. The exciter field breaker failed to open from the main control board and was cycled manually. Main FW (MFW) was manually secured because condensate pump A was manually tripped and condensate B auto-tripped in response to high level in the deaerator, resulting from the turbine runback transient. When MFW was restored, the addition of cooler water caused a reactor coolant system cooldown and Low-Low levels in the C-SG, which tripped the reactor. With the exception of the previous problems, the plant responded normally to stabilize in Mode 3. The root cause of the turbine runback was a relay contact failure in the turbine EHC load reference circuitry, which probably resulted from a design deficiency. The root cause of the exciter field breaker (Alterex) failure was lack of lubrication in the runback circuit. (LER# 8920) LER 395-89020-00 On December 2, 1989, at approximately 2202 hours, operations personnel started a load reduction to 90% power for the monthly turbine control valve testing. When the operator pushed the load selector decrease button for the second 2% reduction in power, the turbine commenced a rapid power decrease (2209 hours). Operations personnel attempted to counter the loss of load by selecting manual increase; however, the turbine controls failed to respond, and the turbine was manually tripped when turbine power decreased below p-9 (power permissive less than 50% rated thermal power). The exciter field breaker initially failed to open from the main control board (MCB). An operator was immediately dispatched to locally open the breaker. The breaker finally opened after several attempts to cycle the breaker from the MCB. Main feedwater was manually secured at 2220 hours, when the turbine runback transient caused a high level in the deareater (DA). When main feedwater was restored at 2221 hours, the addition of cooler (280ºF) water caused a rapid RCS cooldown and steam generator levels to shrink to below the Low-Low steam generator level reactor trip set points. A reactor trip occurred at 2222 hours on C steam generator Low-Low level, with the exception of the previously mentioned problems the plant response was normal. A failed turbine control circuit board was replaced and the exciter field breaker PMD prior to authorizing the plant restart. Additional actions have been initiated by SCE&G to modify the turbine control circuit and increase the PM frequency on the exciter field breaker.
1/17/91	None Turb. POT Wearout Fail	While the unit was at full power, a small loss of power was indicated on the control panel from the turbine controller fluctuating minutely. The system was degraded as power only fluctuated slightly (1 of 2 controllers). The plant was affected slightly. The other controller stabilized the power (201-018-541a). The EHC electronic controller had a load limit potentiometer, with variation of resistance due to aging causing the fluctuation. The potentiometer was replaced with a new one, the controller calibrated, and the channel 1 put in service.
7/10/91	Forced Turb. Solenoid Fail	Turbine trip due to turbine master trip solenoid A failure and stop valve solenoid #2 failure.
7/20/91	Forced Turb. Solenoid Fail	The turbine was taken off-line to replace turbine master trip solenoids A and B.
1/6/92	None Turb. Drift LRM	Operator 3ms cv0108 for turbine control valve 4 did not go to 100% open as designed when the shell warming mode was selected. The valve only went to 75% open. The unit was shutdown and preparing to start back up after maintenance. The load reference demand was at approximately negative 7% instead of 2%. The suspected cause of the misadjustment was that the load reference motor (LRM) was below its normal position. The motor was set for 0.068 VDC when it should have been set for 0.100 VDC plus or minus 25 MVDC. Also, the voltage comparator a69 was slightly off low due to drift. The R43 potentiometer on voltage comparator card a69 was adjusted to ensure that the LRM was at the 2% load reference position.

DATE	TYPE	NARRATIVE
1/28/92	LoadRed Drift CVAMPL Wearout LimitSwt Turb.	Main turbine control valves cv3 (1ms cv0109) and cv4 (1ms cv0108) did not go fully open as expected when shell warming was selected in the control room. This failure of the valves to fully open had no significant effect on main steam system or plant operations (plant power was not limited). Turbine control valve amplifier card a80 (a piece part of 1ehcmi0008, electrohydraulic control (EHC) controller) was slightly out of adjustment low. Apparently its potentiometer, r4, had drifted. The signal was reading 4.972 VDC and should have been 5.025 VDC. After calibration, the limit switch contacts did not close properly, and valve cv3 indicated an intermediate position. Potentiometer r4 was set to the proper set point (5.025 VDC) specified in the procedure ip / 0 / b / 0280 / 15b. All 4 control valves were then opened. The limit switch was mechanically actuated, but its contacts had not changed state. After mechanically cycling the switch several times to wipe the contacts, valve cv3 indicated open (only indication was affected).
2/22/92	None Turb. Relay Fail	With the plant at full power during surveillance testing, number 3, the main steam combination intercept and intermediate stop valve, only stroked 90% closed, then re-opened immediately. The function of this valve is to close upon turbine trip to protect the turbine, then slowly open to release steam from the moisture separator reheaters (MSR). This could have resulted in degraded train had the valve been called upon to operate because of inadequate steam control from the B-MSR to one of the low pressure turbines. There was no effect on the plant. Cause was attributed to an electrical spike from relays in the control circuitry to the valve's solenoid. The contact between two relays was defective. Root cause is unknown. The two defective relays were replaced in the electrohydraulic control panel and the valve tested satisfactorily.
2/24/92	None Turb. Tmptur Drift	With the plant operating at 100% power, the number 3 main steam control valve went from 62% to 55% open. This resulted in reduced power operation due to a decrease in steam demand, a reactor coolant system temp., and pressure increase. These all contributed to degrading operation of channel C. The cause of the valve closing 7% is unknown. A suspected cause is that the room was hotter than normal due to the air conditioning being out of service and that temp. Change resulted in set point drift of the backup overspeed trip and the backup speed amplifier. This set point drift caused erratic output of the controller. No corrective action was taken. Returned to normal after approximately 20 minutes.
3/01/92	Forced Proc TSI Positioner Air	Prior to this event, the unit was at 40%, powering up from 6% following the completion of planned maintenance activities. An I&C technician troubleshooting the rewiring of the main turbine vacuum pressure switches placed multimeter leads across the wrong terminals, causing actuation of the high exhaust hood temperature circuitry. The rewiring of the pressure switches resulted in the addition of a redundant power source to the turbine vacuum trip circuitry, of which the I&C technician was unaware. This resulted in an anticipatory reactor trip system trip of the reactor. A failure of the position feedback arm on turbine bypass valve during the event resulted in the valve failing open causing a slight post trip overcooling of the reactor coolant system. The arm failure was most likely due to reaction forces, resulting from moisture within the valve flashing to steam and/or degraded instrument air at the valve when it was challenged during the transient. Several work control issues contributed to the cause of the reactor trip, including: inadequate job pre-planning and evaluation, inadequate work practices, and noncompliance with station procedures during the planning and execution of the work order. (LER# 9202)

DATE	TYPE	NARRATIVE
7/03/92	Forced Elec Invrtr Fail	Operators' inability to isolate and test a nonsafety-related inverter after maintenance without potentially losing power to the 120 VAC buses led to a brief loss of power to a bus supplying the turbine electrohydraulic control system (TEHC) during the replacement of an inverter circuit board. The TEHC then closed the main turbine valves, leading to an automatic reactor trip on high pressurizer pressure. The root cause of the event was a resistor with a bad connector on the static switch drive board. This resistor was replaced properly, but a jumper to the board was not replaced. Also during the repair, a wire was pulled off of the gate of static switch inverter SCR12. Because this board was not tested, due to the concern mentioned previously, the loose wire caused voltage to fluctuate on the TEHC bus. Several contributing causes were listed, contributing to the inverter failure. After the reactor trip, pressurizer safety valve RC-142 failed open, causing high pressure in the pressurizer quench tank, rupture of the rupture disk, and leaking ~21,500 gallons of contaminated water to the contaminated building sump. The root cause of the malfunction of RC-142 was the adjusting bolt locknut that loosened and allowed the set pressure adjusting bolt to back out during valve actuation due to valve vibration during discharge, thus lowering the valve set pressure. Contributing causes to the failure of RC-142 included inadequacy of the valve refurbishment procedure and lack of a positive locking device to prevent the adjusting bolt from moving. (LER# 9223) LER 285-92023-00 On July 3, 1992, at 2336, while the plant was operating at 100% power, the reactor protection system automatically tripped the reactor due to high pressurizer pressure. The event was initiated as a result of maintenance on a nonsafety-related inverter. During replacement of a degraded circuit board, power was momentarily lost to the instrument bus that supplies power to the turbine electrohydraulic control system resulting in closure of the turbine control valves. A subsequent failure of a pressurizer code safety valve resulted in high pressure in the pressurizer quench tank that blew the tank's rupture disk and resulted in the loss of approximately 21,500 gallons of contaminated water to the containment building sump. The consequences of the event are bounded by the station updated safety analysis report. The root cause of the momentary loss of power to the instrument bus was determined to be the inability to isolate and test the nonsafety-related inverters after maintenance without potentially losing power to the respective 120 vac instrument buses. The root cause of the malfunction of pressurizer safety valve rc-142 was determined to be the adjusting bolt locknut that loosened and allowed the set pressure adjusting bolt to back out. Corrective actions include a modification to enhance the ability to test the nonsafety-related inverters, addition of a positive mechanical locking device for the pressurizer safety valve adjusting bolts, and completion of a comprehensive recovery/restart action plan.

DATE	TYPE	NARRATIVE
8/22/92	Forced Elec PwrSup Fail	As the plant was operating at 100% power, the reactor automatically tripped on thermal margin/low pressure. The event was initiated by the failure of an AC-to-DC converter (Acopian), which affected the first stage turbine pressure signal and resulted in the repositioning of the turbine control valves. This repositioning caused an increase in the reactor coolant system pressure that was terminated by a premature opening of one of two pressurizer safety/relief valves (PSRVs), resulting in the rapid depressurization that caused the reactor trip. Upon receiving the reactor trip signal, the main turbine tripped and the emergency DGs started. A contributing cause to the converter failure was the 1978 modification that removed the backup power supply to the transmitter powered by the Acopian converter. The premature opening of the PSRV was that the previous valve (laboratory) test environment did not provide an adequate representation of the actual field environment. A contributing factor was the material differences in the PSRVs, which was believed to accentuate the problem because of different thermal expansion coefficients. (LER# 9228) LER 285-92028-00 On August 22, 1992, at 0152 (CDT), while the plant was operating at 100% power, the reactor protection system automatically tripped the reactor on thermal margin/low pressure (TM/LP). The event was initiated by the failure of an AC-to-DC power converter, which affected the first stage turbine pressure signal and resulted in the repositioning of the turbine control valves. The decrease in secondary steam demand caused an increase in reactor coolant system (RCS) pressure, which was terminated by a premature opening of one of two pressurizer safety relief valves, followed by the reactor trip. The root cause of this event was the failure of an AC-to-DC power converter in the turbine electrohydraulic control (EHC) panel. The root cause of the premature lift of rc-142 was that the (laboratory) test environment in which valve set pressure qualification was performed and did not provide an adequate representation of the actual field environment. Corrective actions include a modification to change the power source for EHC pressure transmitters, reducing the pressure set point for initiating a high pressurizer pressure trip and power-operated relief valve operation and adjusting pressurizer safety valve set pressures using revised test procedures.
8/26/92	AtSD FVCard Turb. Wearout Fail	With the reactor shutdown, two frequency-to-voltage converters (piece parts of the EHC unit) were found causing electronic noise (erratic output) during a special inspection by the vendor. This erratic output might have resulted in erratic EHC control if the plant would have been at power. Thus the system was degraded. There was no plant effect because the problem was corrected prior to plant restart. The deterioration of the converters is believed to have been caused by aging. The faulty converters were replaced and calibrated. The reactor was started, and the EHC unit functioned properly.
10/28/92	Forced TSI TBWD Proc	Personnel failed to adjust the turbine thrust bearing wear detector set point following maintenance, resulting in a turbine and reactor trip from 16% power during power ascension. The maintenance work order did not specify the need for set point adjustment. (LER# 9212)
1/26/93	Forced Gen Proc	LER 287-93001-00 On January 26, 1993, at 1005 hours, while operating at 100% full power, Unit 3 tripped from a reactor-protective system anticipatory trip signal. While troubleshooting a problem in Unit 3's power factory meter transducer, instrumentation and electrical technicians incorrectly tested the voltage input of the transducer with a multimeter in the current measuring mode. This resulted in a partial loss of power to the generator output megawatt meter and a false signal to the integrated control system. The turbine control valves opened in response to this false signal to recover the apparent lost megawatts. A large decrease in feedwater pump system actuation circuitry actuation started the emergency feedwater pumps and tripped the main turbine. Main turbine anticipatory trip signal tripped the reactor. Post trip response was normal. During the trip recovery, while transferring from the emergency feedwater to the main feedwater pumps, a loss of automatic initiation of both emergency feedwater flow paths resulted when both emergency feedwater control valves were not placed in auto, as directed by procedure. The cause of the unit trip was inappropriate action (improperly followed the correct procedure). Corrective actions included replacement of the blown fuses and faulty transducer, revision of the station drawings, and individual counseling to improve personnel performance.

DATE	TYPE	NARRATIVE
5/5/93	None Turb. LRMgear Sticking Lubrcnt	Unit coming out of refuel outage. The gears on the load reference motor, a piece part of the load control unit, were found to be worn. This caused the motor to bind in place, not allowing the generator to be loaded. This caused a delay in placing the unit back on the grid. The gears were manually moved; this allowed the bound gears to move freely and allowed the load reference motor to move as required. It is suspected that normal usage caused the gears to wear. Initially, the gears were freed manually; this allowed for proper operation until the load reference motor could be replaced. The load reference motor was replaced like-for-like during the next refuel outage.
6/03/93	Forced Turb. Noise	A plant equipment operator opened the doors of the electrohydraulic control (EHC) cabinet to check the temperature, as part of his normal rounds. The EHC monitor panel trouble alarm, along with several other alarms, were annunciated on the control room main boards. Ten seconds later, the reactor tripped from 100% power on high pressurizer level. The main turbine generator EHC system initiated a signal that caused the main turbine intercept valves and control valves to close. The main turbine rapidly decreased load, resulting in a load imbalance between the reactor plant and the steam plant; this caused an increase in reactor temperature and pressure. Both power-operated relief valves (PORVs) and several SG safety valves opened. The reactor tripped, causing an automatic turbine trip. The root cause of the reactor/turbine trip was the closing of the main turbine intercept and control valves in response to signals from the EHC cabinet. The cause of the EHC signals was not determined. The opening and closing of the EHC cabinet doors by the plant equipment operator was determined to be essentially coincident with an EHC trouble alarm and an indication of intercept valve closure. Probable causes are electromagnetic field induction while the doors were open or vibration from the door opening or closing. (LER# 9313) Plant in Mode 1, at 100% power. Electrohydraulic control (EHC) monitor panel trouble alarm, along with several other alarms, were annunciated on control room main boards. Approximately ten seconds later, the reactor tripped. The main turbine generator EHC system initiated a signal, causing the main turbine to rapidly decrease load. The sudden decrease in load resulted in an increase in pressurizer pressure, resulting in a reactor trip. The root cause of the automatic reactor/turbine trip was the closing of the main turbine intercept and control valves in response to signals from the EHC cabinet. The signals are attributed to spurious relay actuations as a result of operations within the cabinet. Potential causes are electromagnetic field induction while the cabinet doors were opened by an operator during normal rounds or vibration from the door movement. Troubleshot and found the signal causing the valves to close could not be reproduced. To minimize the probability of reoccurrence, caution tags are now hung on the EHC cabinet doors that require control room notification before opening the cabinet doors. LER 336-93013-00 On June 3, 1993, at 1624 hours, with the plant in Mode 1 at 100% power, the main turbine generator electrohydraulic control (EHC) system initiated a signal that caused the main turbine to rapidly decrease load. The sudden load drop caused an increase in pressurizer pressure, resulting in a reactor trip. The EHC signal has been attributed to spurious relay actuations as a result of operations within the EHC cabinet. Operators performed emergency operating procedure eop 2525, standard post trip actions, and all safety-related equipment performed as expected. This is being reported pursuant to requirements of paragraph 50.73 (a) (2) (iv), reporting any event or condition that resulted in manual or automatic actuation of any engineered safety feature system, including the reactor protection system (RPS).
6/24/93	None CVAMPL Drift Turb.	2EHCMI0008 is the electrohydraulic control (EHC) electronic controller that sends valve position signals to the main steam control valves. Main steam control valve #4 would not go to the full-open position during steam chest warming. This degraded the system's ability to supply steam to the turbine. The problem occurred during unit startup following a refueling outage. There was no plant effect, and unit startup was not delayed. A bias voltage card (card a80) in the turbine panel (piece part of the EHC electronic controller) was out of adjustment. The voltage was low. It was found at 4. 980 VDC and should have been 5.000 to 5.050 VDC. The root cause of the low voltage could not be determined. Technicians adjusted the voltage up to 5.050 VDC. Proper operation of the valve was verified.

DATE	TYPE	NARRATIVE
8/23/93	Forced P.E. Turb.	I&C technicians and a non-licensed operator were performing speed control calibrations. The 1ADA input and output breakers, circuit #1, were opened to allow for a peak inverse voltage test on the DC power system diodes. Upon opening the breaker, one of the unit's AC and DC I&C power panel boards was lost. The supply breaker input leads in the alternate power path were found rolled, causing the loss. That resulted in the loss of the 125 VDC EHC circuit, tripping the main turbine and causing an anticipatory reactor trip from 100% power. Main FW started; however, due to an inappropriately installed output limiter card in the integrated control system, main FW pump speed was limited. That resulted in the initiation of the dryout protection circuit, auto-starting both motor-driven emergency FW pumps. The root cause of the rolled diode input breaker leads was attributed to inappropriate actions, improper action, and lack of attention to detail. (LER# 9308)
11/20/93	Forced Turb.	Shutdown for turbine EHC maintenance and repairs.
3/8/94	None Turb. POT Fail Wearout	While operating at 80% power, a 28 mwe step load increase was recovered after 15 seconds without operator interaction. The following day, the load step changed from 725 mwe to 805 mwe and remained there until operators lowered the load limit potentiometer (piece part of main turbine electrohydraulic controller) and returned to 720 mwe. The load limiter remained in operation, as indicated by the load limiter light on the control panel. However, the load limiter light extinguished, and operator action was required. GE was called, it was surmised that the problem could be due to a combination of a faulty l0ad limiter circuit and drift in the speed error signal input to the control valve amplifier. GE recommended the load limiter be raised above the load set to prevent further transients prior to shutdown for rf8. The decision was made to operate under load limit circuitry with the load set dialed into a value slightly higher than the load limit value, allowing the load set to take control if the load limit circuit should fail. To preclude future failures, a task was implemented to replace the load limit potentiometer (pot) every other refueling. This pot was not originally designed for continuous operation, and the most likely cause of the spiking is the generation of a dead spot on the potentiometer, dirt, corrosion, or scaling on the wiper due to continuous operation at a given power level. The load limiter potentiometer mounted on the control panel, and the setback limit runback board were replaced during rf8. All sat.
6/16/94	Forced Turb. SADI Fail	The unit tripped from 100% power due to an automatic actuation of the RPS. The RPS signal was the result of low steam generator (SG) water levels due to FW shrink after all four main turbine stop valves unexpectedly closed during weekly valve testing. After the trip, SG levels trended downward. About eight minutes after the trip, the auxiliary FW system actuated to restore SG levels. A cause of the main turbine stop valves closing could not be identified. (LER# 9406) The unit was at 100% power and the main steam system was in operation. Operators were performing a weekly main turbine stop valve (MTSV) test to separately exercise each of the four stop valves. After successfully testing MTSV-3 to shut, operators signaled the valve to open. Instead, the remaining three valves went shut. It was later determined that 1pnl1t11, the electrohydraulic control (EHC) electronic controller panel, sent an incorrect signal allowing the valves to close. The system function of providing steam to the turbine generator was lost. This failure caused the water level in the steam generators to fall, which resulted in an automatic plant trip. An investigation (pdi199400061) determined that the root cause of the failure was the failure of a servo amplifier demodulator indicator (SADI) circuit board (piece part) in the EHC panel. The board most likely failed due to an intermittent failure in a transistor caused by age-related degradation. The valves were cycled several times. Following no repeat problems, the system was returned to operation and the unit restarted (1199403008). One month later, the unit tripped again because the stop valves unexpectedly shut. Investigations of that trip found the failed circuit board, which caused both trips. For the second failure, the SADI board was replaced.

DATE	TYPE	NARRATIVE
6/20/94	AtSD Turb. CardNS Fail	1EHCMI0008 is the electrohydraulic control (EHC) electronic controller, which provides position signals to the main steam stop valves. The unit was preparing for startup following a refueling outage. When the turbine was reset, the turbine main steam stop valves went to the open position instead of remaining closed as designed. This was due to the failure of a circuit card in the controller, which caused the controller to send an incorrect signal to the valves. This degraded the main steam system because one signal to position these valve was lost. There are other instruments and signals that would have worked, if necessary. There was no actual plant effect. A circuit card (piece part of the EHC electronic controller) had defective contacts. This resulted in intermittent contact and caused the valves to go to the open position. The cause of the degraded contacts was not discovered. A new card (piece part) was installed. Proper operation was verified, and no further problems were noted.
7/19/94	Forced Turb. SADI Intrmtnt Fail	The unit tripped from 100% power due to a RPS actuation. The RPS actuation was the result of low steam generator water levels due to level shrink after all four main turbine stop valves unexpectedly closed. During the resulting transient, both RCS power-operated relief valves opened, and one code safety/relief valve began leaking by its seat at approximately 25 gpm. The event was caused by an intermittent failure of a servo amplifier demodulator indicator board in the turbine EHC cabinet 1T11. (LER# 9407) The unit was at 100% power and the main steam system was in operation when all four main turbine stop valves (MTSV) unexpectedly closed. It was later determined that a control board had failed in 1pnl1t11, the electrohydraulic control (EHC) electronic controller panel. The system function of providing steam to the turbine generator was lost. This failure caused water level in the steam generators to fall, which resulted in an automatic plant trip. An investigation (pdi199400061) determined that the root cause of the failure was an age-related intermittent failure of a servo amplifier demodulator indicator (SADI) card in the EHCK panel. When the board failed, MTSV-2 closed. MTSV-2 is the master valve for the other valves, so the remaining three valves closed. The faulty circuit card was replaced. The stop valves were tested satisfactorily, and the unit restarted (19403629). LER 317-94007-01 On July 19, 1994, at 1824, Unit 1 tripped from 100% power due to a reactor protection system (RPS) actuation. The RPS actuation was the result of low steam generator water levels due to level shrink after all four main turbine stop valves unexpectedly closed. During the resulting transient, both reactor coolant system (RCS) power-operated relief valves opened and one code-safety relief valve began leaking by its seat at approximately 25 gpm. The event did not result in any significant potential or actual nuclear or personnel safety consequences. Short-term corrective actions to support a safe unit restart have been completed. The RV manufacturer has initiated process improvements to prevent recurrence of inadequate staking of a disc holder to bellows assembly inside the RV. The root cause of the MTSV closure has been incorporated into an ongoing turbine EHC systems improvement effort.
9/7/94	None Turb. Solenoid Fail Wearout	During normal operation at 100% power, operators performing a weekly surveillance test of the main turbine electrohydraulic control (EHC) power unit observed that the master trip solenoid valve A (1 of 2 master trip solenoid valves that are piece parts of the EHC) failed to trip on demand. Further troubleshooting revealed that the solenoid valve's coil spool was sticking sporadically. One train of turbine trip was degraded. Plant operation was unaffected due to both trains being required to actuate for a turbine trip and discovery of the failure during testing and not during an actual trip condition. The cause of the master trip solenoid valve's coil spool sticking was attributed to charring and swelling of the coil spool due to age-related degradation. This resulted in sporadic movement of the coil spool on demand. The master trip solenoid valve was replaced with like-kind. Post maintenance testing of the valve verified it to be operating properly.
9/13/94	LoadRed Turb. Solenoid Fail	Power hold at 30% for main turbine trip solenoid repairs.

DATE	TYPE	NARRATIVE
11/29/94	LoadRed Turb. Fail Motor	Load reduction to 69% to perform repairs on the main turbine load reference motor.
2/9/95	AtSD Turb. Fail WobCard Ref. Card	The electrohydraulic control electronic controller speed control subsystem output was found to be erratic during preventative maintenance. The unit was in a refueling outage, and the system was in maintenance. There was no significant effect on system or unit operation. Troubleshooting of the component revealed defective wobbulator and speed/acceleration reference cards. The cause was unknown. The cards were replaced and calibrated.
3/16/95	AtSD Design Turb.	LER 336-95011-00 On March 16, 1995, at 1914 hours, with the plant de-fueled, it was determined—following a review of NRC information notice 95-10 potential loss of automatic engineered safety features actuation—that non-qa electrohydraulic control pressure switches ps-4597a, b, c, and d are connected to the reactor protection system (RPS) turbine trip bistables (TTB) without adequate electrical isolation. This design deficiency is the result of inadequate design, which resulted in the downgrading of an RPS input device in 1989 from qa to non-qa without proper consideration for isolation between vital and non-vital electrical circuits associated with a safety system. Design engineering is reviewing the following potential corrective actions: a) restoring all components associated with the RPS turbine trip circuitry to its original qa-cat1 status and b) installing qa-cat1 isolation devices on the input of the RPS turbine trip circuitry. Corrective action will be completed prior to plant startup. This is being reported pursuant to requirements of 10 CFR 50.73 (a) (2) (ii) (b) as a condition that was outside the design basis of the plant.
4/13/95	LoadRed Turb. VCCard Fail	Load reduction to 94% to replace a voltage comparator card in the turbine EHC that was causing turbine load swings.
5/5/95	None POT Fail Wearout Turb.	Unit 1 was at 100% power, and the main turbine (MT) system was in operation. When operators were decreasing the turbine load down by lowering the load limit potentiometer (pot)—a piece part of the 1pnl1t11, the electrohydraulic controls—one notch, indications showed that the MT control valves (CVs) opened 62% to 75%. Other indications, MW output and CV movement, were consistent for the transient observed. After the transient, all components returned to their normal operating parameters. Subsequent adjustments made to the turbine load, via the pot, were completed without incident. The function of providing control (both broad and fine level) was degraded due the degraded electrical circuit within the pot. There was no other effect on the system or plant. The pot was suspected of degraded electrical circuitry (dead spots), which prevented the operators from performing fine-tuning of the turbine load. Although the exact cause of the failure is unknown, dead spots are characteristic of a potentiometer being left in-service over an extended period of time without changes being made to the settings. Over time, this can lead to dead spots. Obtained initial voltage and resistance readings from the pot being replaced, installed the new pot, and adjusted it based on readings obtained during troubleshooting. (Although this pot is critical, it is not a calibrated pot.) Verified proper operation/indication with operations, then returned the equipment to service.
6/11/95	None Turb. LRMgear Sticking Lubrcnt	Unit at 96%, power decreasing to 92% for monthly main turbine control valve testing. While lowering power, it was observed that the #4 control valve was not traveling in its close direction. Power decrease was suspended, and shortly thereafter the #4 control valve quickly went to its close direction. It was found by computer points that the load reference motor (LRM), a piece part of the EHC electronic controller, was not responding to the power decrease signal immediately. A reduced-power operation is chosen due to a slight delay in returning to full-power operation. The failure of the LRM to operate as required was the result of a worn area on the LRM gearing. The cause of the gear wear is not known, but it is suspected to be lubrication-related. The cause of the load reference motor gear wear is not known, but it is suspected to be lubricant-related. The following temporary measures were taken to restore the load reference motor to acceptable operation: the gears were cleaned, lubricated, rotated away from the worn area, and checked for proper operation. The load reference motor will be replaced during 10 rfo scheduled for April 1996.

DATE	TYPE	NARRATIVE
7/23/95	LoadRed TSI TBWD Drift	Power hold at 28% for turbine thrust bearing wear detector calibration.
10/14/95	None Fan Elec Fail Wearout	The plant was operating at 100% power. Operations personnel received a electrohydraulic control system electrical malfunction alarm on the main control board. After investigation, it was found one of the four cooling fans in the bottom of the cabinet had failed. Since there were three fans still in operation, the decision was made to replace the fan at the next refueling outage (rf9). A ty-wrap was installed on the air flow switch to hold it in the closed position to clear the annunciator. There was no effect on the system or the plant. The cause of the fan failure is suspected to be bearing failure due to normal aging. The ty-wrap was removed, and a like-fan was installed. The other three fans were also replaced as a good maintenance practice with like models. All tests were completed satisfactorily (ref: 95o4362 and ncn-5265).
11/20/95	AtSD Turb. Fail CardNS	1EHCMI0008 is the electronic controller for the electrohydraulic controls system portion of the main steam system. During routine preventive maintenance, technicians found two circuit boards (piece parts of the controller) that could not be calibrated within required tolerances. The unit was in a refueling outage when the problems were discovered, so there was no effect on the plant or system. One of the cards had a bad diode. The deadband on the other card was outside allowable limits and could not be calibrated to meet the limits. The faulty diode was replaced, and the card worked properly. The other card was removed, and a new one (exact replacement) was installed. The test procedure was completed, and all components were verified to be operable and within tolerance.
12/23/95	LoadRed Turb. Relay Fail	Power hold at 37% to replace relays in the turbine EHC system.
8/03/96	Forced Turb. SADI Fail	Unit 1 was in Mode 1 at approximately 3% power and the main turbine (MT) system was being prepared to be placed in service. During an inspection of the 11 MT electrohydraulic control cabinet, it was discovered that #2 stop valve servo current was reading positive 6 milliamps while all other servo currents had negative milliamps. The function to control the servo valve current for positioning the stop valve was lost; however, since the MT had not yet been placed in service, there was no other effect on the rest of the system or the plant. Technicians isolated the fault to a SADI card in slot b52 (piece part of 1pnl1t11). The actual cause of the failure is unknown. During further efforts to verify the fault/fix, the manufacturer was contacted to verify the proper part number and it was determined that this was a new replacement card. When the card was installed into slot b52, there were still problems with the circuit. It was found that the b56 card worked in slot b52, and the new card worked in slot b56. It is suspected that the cause of this is a worn card edge connector in slot b52. After the repair, the circuit was verified to work correctly and valve stroke adjusted per operations.
9/14/96	LoadRed Elec PwrSup Fail	Load reduction to 35% to replace EHC power supply.

APPENDIX C
EVENTS FOR BWR PLANT WITH MARK II EHC

DATE	TYPE	NARRATIVE
2/21/88	Forced Turb. P.E. Proc	With the unit in startup at 4% power, an automatic reactor scram was initiated due to turbine stop valve closure coincident with greater than 40% power, as sensed by first-stage turbine pressure. Operators failed to maintain turbine first-stage pressure within required limits during the turbine shell warmup procedure, allowing the first stage to increase to a pressure indicative of 40% rated power. The operator had neglected to maintain the correct turbine first stage pressure, relying on steam pilot valve position and turbine shell temperature for indication rather than pressure indicators as required by procedure. (LER# 8807)
6/23/88	Forced Turb. TripLtch Fail Instltn	A reactor scram from 80% power occurred due to an unexpected turbine trip. At the time of the event, control room operators were performing weekly turbine testing requirements. The cause of the turbine trip was a mechanical failure of the trip latch assembly due to improper clearances within the mechanism established during manufacturing and initial installation. (LER# 8826)
8/25/88	Forced Gen	LER 458-88018-04 At 1232, on 8-25-88, with the unit at 100% power (operational condition 1), the reactor automatically scrammed due to a turbine control valve fast closure caused by a loss of main generator field excitation resulting in automatic main generator and turbine trips. Immediately following the scram, reactor pressure spiked to a peak between 1,100 psig and 1,117 psig, causing the five Low-Low set safety relief valves to cycle per design. The turbine bypass valves opened as required, and the reactor recirculation pumps transferred to slow speed per design. Reactor water level initially decreased to plus 4 inches, as indicated by the wide-range instruments due to the reactor pressure spike. The high pressure core spray (HPCS) and reactor core isolation cooling (RCIC) systems injected as a result of a spurious low reactor water level 2 signal caused by a hydraulic perturbation in the reactor water level instrument reference lines. As a result of the feedwater flow continuing (due to the a feedwater control valve being in the manual mode at 50% open) in conjunction with the HPCS and RCIC injections, reactor water level rapidly increased to level 8, causing the HPCS injection valve and the RCIC steam supply valve to close and the reactor feedwater pumps to trip per design. There was no significant adverse impact on the safe operation of the plant or to the health and safety of the public as a result of this event because the reactor scram placed the unit in the safe shutdown condition.
11/11/88	SwitchGear Forced Fail MPxfmr	LER 461-88028-00 On November 11, 1988, with the plant in mode 1 (power operation), the C-phase main power transformer (MPT-C) failed, causing a generator-to-transformer differential relay trip of the main generator. The trip of the main generator resulted in a turbine trip and an automatic reactor scram because of the turbine control valve fast closure signal. The cause of this event is attributed to an internal fault on the high voltage side of the transformer. The MPT c was replaced with a spare transformer of the same type and manufacturer. Electrical tests and oil samples of the MPT-A, MPT-B and the spare transformer indicated acceptable insulation levels and dissolved gas contents. The results from the tests and samples indicate that the three main power transformers are in satisfactory condition. Will perform a visual inspection of the MPT-C and perform tests to determine the extent of the fault and the scope of the necessary repairs. The existing preventive maintenance requirements for the main power transformers will be evaluated to determine if changes are warranted.

DATE	TYPE	NARRATIVE
1/15/89	Forced Turb. Relay Fail	Load reduction followed by shutdown to replace turbine control circuit relay K-4.
2/25/89	Forced TSI Relay Fail Wearout	An auto reactor scram occurred during a routine turbine upper thrust bearing wear detector test. The scram was caused by a turbine trip, which was caused by a defective test bypass relay. The relay failed to open the trip bus circuit as designed to prevent a turbine trip while testing the thrust bearing wear detector. The RCIC system injected due to a spurious low reactor water level signal. The spurious low level signal was caused by a pressure perturbation, which was caused by the fast closure of the turbine control valves. The perturbation was sensed by the reactor water level instrumentation. (LER# 8908) LER 458-89008-00 At 0041, on 2/25/89, with the unit at 78% power (operational condition 1), the reactor automatically scrammed while performing a routine upper thrust bearing wear detector test in accordance with operations section procedures (OSP)-0101. The scram occurred as a result of a turbine trip caused by a defective bypass relay. The relay failed to open the trip bus circuit as designed to prevent a turbine trip while testing the thrust bearing wear detector. Immediately following the turbine trip, the reactor core isolation cooling (RCIC) system injected due to a spurious low reactor water level 2 signal. The spurious signal resulted from a pressure perturbation, caused by the fast closure of the turbine control valves, being sensed by the reactor water level instrumentation. Reactor water increased to level 8, and the RCIC steam supply valve closed per design. As corrective action, a turbine trip bypass switch will be installed to be utilized during the weekly testing to temporarily bypass turbine trips that might be inadvertently caused by spurious relay actuations within the main turbine electrohydraulic control panel. Additional corrective action is being implemented during the second refueling outage to prevent spurious RCIC initiations. There was no adverse impact on the safe operation of the plant or to the health and safety of the public as a result of this event because the reactor scram placed the unit in the safe shutdown condition.
6/28/89	SwitchGear Forced Fail Relay Corrosion	LER 461-89028-00 On June 28, 1989, with the plant in mode 1 (power operation), the C-phase main power transformer (MPT) sudden pressure sensor relay malfunctioned, causing a trip of the main generator. The trip of the main generator resulted in a turbine trip and an automatic reactor scram because of the turbine control valve fast closure signal. The cause of this event is attributed to a spurious signal from the malfunctioning sudden pressure sensor relay. The sudden pressure sensor relay malfunctioned because of internal corrosion resulting from water intrusion into the relay. The sudden pressure sensor relay was replaced with a sensor relay that has an air vent to prevent moisture buildup inside the relay. The sudden pressure sensor relays were replaced in the other two main power transformers and also in the reserve auxiliary transformer and the emergency reserve auxiliary transformer.

DATE	TYPE	NARRATIVE
4/07/90 4/17/90	Forced Turb. Design	A reactor scram occurred from 79% power while testing the main turbine combined intermediate valves. The scram occurred on low turbine EHC system pressure. Apparently, this low pressure was caused by multiple combined intermediate valves stroking when the #4 CIV was being tested. (LER# 9014) LER 458-90014-00 At 0154, on 4/07/90, with the reactor at 79% power (operational condition 1), a reactor scram occurred while testing the main turbine combined intermediate valves (CIVs) (*v*). The scram occurred on low turbine electrohydraulic control (EHC) system pressure. This low pressure appears to have been due to multiple CIVs stroking when the number 4 CIV was being tested. However, repeated testing failed to bring about a repetition of the event that caused the scram. Corrective action included replacement of two solenoid valves, five relays, and the electrical trip valve. A modification has been installed to provide additional relay contacts between the CIVs and the test circuit. In addition, the valve testing procedure has been revised to require increased monitoring of valve position. This event resulted in the actuation of the reactor protection system (RPS). Therefore, this report is submitted pursuant to 10 CFR 50.73 (a)(2)(iv). This event caused no adverse impact on the health and safety of the public. In response to the scram on 4/7/90, the plant was manually shutdown, and a modification was installed to provide additional relay contacts between the CIVs and the test circuit to prevent spurious signals from reaching the CIVs not being tested. (LER# 9014)
7/9/90	Forced Gen Relay Proc	LER 461-90013-00 On July 9, 1990, with the plant in power operation at 91% reactor power, main generator overvoltage/hertz protection relay 59/81-1 actuated. After a designed 45-second time delay, the main turbine generator tripped via turbine control valve fast closure, which caused an automatic reactor scram. Additionally, groups 2, 3, and 20 containment isolation valves actuated as a reactor vessel water low-level trip occurred. Investigation determined that relay 59/81-1 had actuated prior to exceeding its design set point because it was out of calibration. The cause of the relay being out of calibration cannot be determined. Probable causes are personnel error in reading the test instrument during calibration and/or test instrument error during calibration caused by a fluctuating voltage source. Corrective actions include: recalibrating two relays and verifying set points of a sample of other relays calibrated during the same period, issuing detailed procedures for calibrating protective voltage relays, investigating qualifying a power station technician to perform relay testing, recently purchasing new digital test equipment, and briefing each operations crew on generator limitations and abnormal voltages.
12/9/90	None Gen MGInst Dirt	With the plant at full power and the main generator voltage regulator in automatic control, a control room operator noticed the exciter field voltage for the main generator oscillating. Failure to control field voltage could cause generator core damage due to overheating. Voltage regulator was placed in manual operation, requiring greater operator attention. There was no other impact to system operation or to the plant. Investigation revealed that the insulators and contact surfaces of the signal potential transformers were dirty. These potential transformers are piece-parts of the regulator. No explanation could be given for the excessive dirt found in the cabinet. The insulators and contact surfaces of the potential transformer cabinet were cleaned. The regulator was placed in automatic operation and monitored for 6 days. Regulator operated satisfactorily. The regulator was returned to service.
1/1/91	AtSD Turb.	During surveillance testing, with the control rods inserted and with the reactor in power ascension following refueling, the turbine stop valves unexpectedly closed. The failure was identified by control room alarms. Failure written against electrohydraulic control unit electronic controller because it controls the Stop Valves. The stop valve closure is considered to have been spurious because troubleshooting could not duplicate the stop valve closure. No further action was taken, and the system was restarted without problem.

DATE	TYPE	NARRATIVE
3/4/91	AtSD Fail Turb. Relay	With the plant shutdown during the weekly turbine valve operability surveillance, the number one intermediate stop valve (ISV) failed to close. Trouble shooting revealed that two relays in the control circuit failed to operate. The effect of this failure is minimal since the ISV is a backup device for turbine overspeed protection. The failure of the intermediate stop valve to close was traced to the failure of two associated control relays. It is unknown why these relays failed to perform. Replaced two relays in-kind. These were deutsch part number e210-1173 (or-1347). All control intermediate valves were opened to reset the control logic and proper operation of the stop valve was verified.
3/8/91	Forced Turb. Fail Connection Intrmtnt	While at 15% power, and during performance of the main turbine acceleration process, the high pressure turbine tripped. The main steam system effect was the turbine being tripped off-line. Troubleshooting revealed the suspicion of an intermittent loss of speed signal to the turbines electrohydraulic control system. Field investigation resulted in the possibility of an intermittent contact between the electrohydraulic control systems electronic component card (turbine 5.5% arming card) and the component card rack mechanism. The exact intermittent or dirty contact was not discovered and is unknown. Control and instrumentation personnel removed the suspected turbine 5/5% arming card, reseated it into the card rack mechanism. Operations continued on with the acceleration process, proper turbine acceleration occurred.
6/22/91	LoadRed SB&PR PwrSup Fail	Load reduction for turbine bypass valve EHC control power supply replacement.
1/4/92	SwitchGear Forced Fail MPxfmr	LER 461-92001-00 On January 4, 1992, with the plant in power operation at 99% reactor power, the B-phrase main power transformer (MPT-1b) failed due to an internal fault. The transformer failure resulted in a turbine generator trip and an automatic reactor scram. The automatic reactor scram occurred due to the turbine control valve fast closure. Within seconds of the scram, the turbine-driven reactor feed pump (TDRFP) 1b tripped. Additionally, after the reactor scram was reset, a scram discharge volume (SDV) drain valve failed to reopen, and the SDV vent valve only opened to an intermediate position. The cause of the scram was an internal fault in MPT-1b. The cause of the TDRFP-1b trip was attributed to a worn thrust bearing, and the cause of the SDV vent and drain valves failing to reopen was attributed to air leakage past the seat of three-way solenoid valve. Corrective actions for this event include replacing the failed MPT with a spare MPT, restoring the TDRFP-1b thrust bearing clearance to original manufacturer specifications, and rebuilding the three-way solenoid valve.
3/7/92	AtSD Gen Fail Relay Surge	With the plant shutdown for maintenance, an operator on rounds received an electrical transient from the grid due to a downed transmission line. The transient caused the failure of1e33a*k601, which provides power to the main steam isolation valve (MSIV) initiation logic. Failure of this power supply causes the inboard MSIVs to close. Since the plant was shutdown, there was no impact to the plant. However, the inboard isolation valves were declared out of service, causing a loss of system function. The power supply was determined to have failed due to the power transient (spike) feed into the system by the transformer failure. (The transformer was in an off-site switch yard.) The power supply was replaced like-for-like and monitored for spikes. It was then returned to service.
5/12/92	AtSD Turb. VPCard Drift	The unit was in a refuel outage. During the performance of a surveillance test (SVT), a main steam stop valve took seven minutes to open. Acceptance criteria for this valve is 10.0 sec. ±1.0 sec. Troubleshooting revealed that the valves' position controller was out of calibration. Since the primary function of the stop valve is to quickly shut off steam flow to the turbine under emergency conditions, there was no effect to the system or plant since the failure was in the open direction.///The cause of the controller being out of adjustment was attributed to drift. The controller was recalibrated, and the SVT was performed with satisfactory results.

DATE	TYPE	NARRATIVE
5/22/92	AtSD Turb. VPCard Drift	The unit was in a refuel outage. During the performance of a surveillance test, the C-train turbine intermediate stop valve in the main steam system would not fully open. The valve would only open 70%. Troubleshooting revealed that the valve position card (piece part of the controller) was out of adjustment (low). This failure degraded the C-train, but had no adverse effect on the plant.///The cause of the failure was determined to be set point drift. The position card bias was reset to proper setting. The valve was stroked with satisfactory results.
5/27/92	AtSD Turb. VPCard Drift	The unit was in a refuel outage. During main turbine shell warming, the control room received an indication that the number 4 turbine control valve for the main steam system did not open 100%, as required. The valve would only open 85%. Troubleshooting revealed the valve position controller was out of adjustment (high). This failure degraded the B-train control valve function of regulating steam flow to the high pressure turbine. There was no effect to the plant.///The cause of the problem was determined to be set point drift of the controller. The controller was adjusted to allow the valve to open 100%. No retest was required per the system engineer.
6/12/92	None TSI Valve Wearout Fail	The unit was at 7% power, coming out of a refuel outage. While performing a plant test instruction (PTI) to the main turbine, with the turbine at 1,800 rpm, the turbine tripped on overspeed but did not trip electrically when the trip button was pushed. After one to two minutes, the turbine did trip electrically. Troubleshooting revealed that an electrical trip valve (piece part of the turbine electrohydraulic control power unit) was defective. This failure prevented the main turbine from tripping electrically and restricted the plant to 15% power.///The cause of the failure was attributed to wearout of the electrical trip valve. The electrical trip valve assembly was replaced with a spare. The turbine trip/reset test was reperformed with satisfactory results. The plant continued power ascension.
6/15/92	None Turb. VPCard Drift	The plant was at 35% power during power ascension. The plant was coming out of a refuel outage. While performing a surveillance test, the A-train turbine intermediate stop valve in the main steam system did not stroke closed. Troubleshooting revealed that the valve position card (piece part of the controller) was out of adjustment (high). This failure degraded the A-train but had no adverse effect to the plant.///The cause of the failure was determined to be set point drift. The bias adjustment had drifted high. The position card bias was reset to proper setting. The valve was stroked with satisfactory results.
10/18/92	None Fail Gen MGInst Wearout	With the plant in startup and the operators using the manual voltage regulator control to control the main generator output, operators noted that the manual control was not tracking with the automatic control, making it difficult to null the output voltage. This degraded system operation. There was no effect to the plant because operations was able to complete the swap of control to automatic operation. Investigation of the controller circuit revealed that voltage transducer TFDCPT, a piece part of the voltage regulator, was out of tolerance. Failure was attributed to normal and expected instrument drift. The transducer was adjusted into specification, and the control circuit was retested satisfactorily.

DATE	TYPE	NARRATIVE
11/24/92	Forced Fail SB&PR PressAmp MSPS	The reactor scrammed from 96% power due to problems with the steam bypass and pressure regulator system. Due to failures in the A pressure amplifier card (set point drift) and the B pressure transmitter, there was a mismatch between the A and B regulator outputs, which caused the turbine control valves to change from 35% to 23% open. This resulted in a pressure increase, and the unit scrammed on high neutron flux. In addition, contributing factors were that the pressure amplifier lead/lag adjustments, resonator adjustments, and compensator adjustments were improperly set up since initial plant startup. These improper adjustments made the control system sluggish in response to pressure transients. (LER# 9226) LER 458-92026-00 On November 24, 1992, at 00:54:49.9, the reactor scrammed from 96% power due to problems with the steam bypass and pressure regulator system. As a result of a mismatch between the A and B regulator outputs main turbine control valves changed position from approximately 35% open to 23% open. The resulting pressure increase caused a corresponding increase in reactor power. The plant then scrammed on high neutron flux; therefore, this report is submitted pursuant to 10 CFR 50. 73 (a)(2)(iv) to document the reactor scram. The root cause of the scram consisted of failures in the A pressure amplifier card and the B pressure transmitter. These components have been replaced. Failure of the pressure regulator is bounded by USAR chapter 15.2 increase in reactor pressure. The high neutron flux scram set point limits the peak fuel surface temperature and ensures that the minimum critical power ratio (MCPR) was still within the safety limit for this transient. All plant systems responded as expected, and the reactor was placed in a safe shutdown condition.
4/20/93	AtSD Turb. Proc	LER 458-93007-00 On April 20, 1993, at 0911, with the reactor in cold shutdown (operational condition 4), an isolation of inboard and outboard main steam isolation valves and main steam line drains occurred. The isolation signal was low condenser vacuum. GSU is submitting this report pursuant to 10 CFR 50.73 (a)(2)(iv) as an automatic actuation of an engineered safety feature (ESF). The root cause was determined by barrier analysis. The root cause is that the operating crew did not understand the specific details of the turbine control logic for the unique maintenance conditions that existed at the time of the event. This lack of understanding was also responsible for the absence of precautions in operations department procedures. Therefore, the protection of a procedural barrier did not exist. Corrective actions include revision of operations policies and procedures. All systems functioned as designed during this event.
5/27/93	AtSD TSI Relay Fail CoilOC	Plant was in cold shutdown with main turbine system in surveillance testing when the main turbine would not reset after a trip. The oil reset solenoid valve (ORSV) was not receiving the signal to reset because the k17 (deutsch relay) relay coil was open. K17 is a piece part of a circuit board in the main control panel (1h13p0821) that closes on demand to initiate a reset of the ORSV. If an actual trip had occurred, the system would not have been able to reset to resume operations. Plant was unaffected due to shutdown status.///Cause of the failure was unknown. K17 relay was replaced with like component. Turbine trip was reset satisfactorily.
7/2/93	None Gen Relay Wearout Fail	Plant at 60% power. Operator noted the main generator voltage regulator manual set point was not tracking the voltage regulator auto set point. This would cause a problem if the voltage regulator control shifted to auto control to manual control, which could possibly damage main generator. This would cause a degraded effect on main generator system but had no actual effect on the plant. The ATA (automatic tracking power relay) and the 43a (transfer relay) contacts were not operating properly (not lined up as they should be) and were out of calibration. Wear and aging were the suspected cause of wearout of the relays. Relays are piece parts of the voltage regulator. Performed bench calibration check on the 43a relay. Relay checked satisfactory and was reinstalled. The ATA relay was replaced like-for-like. System functionally tested. Test satisfactory.

DATE	TYPE	NARRATIVE
7/09/93	AtSD SB&PR	With the plant operating at 100% power, both reactor recirc pumps unexpectedly shifted from fast to slow speed due to failure of both pump suction resistance temperature detectors (Rosemount). Operators manually scrammed the reactor from 52% power when the plant entered the region of potential instability of the power to flow map. After the reactor trip, the following equipment failures occurred: 1) The turbine did not automatically trip following the reactor trip, so operators manually tripped the turbine. Subsequent investigation revealed that the main turbine control valves did not stay closed and that the steam bypass and pressure regulation system required adjustments. 2) The A hydrogen analyzer indicated high due to instrument drift. 3) The scram discharge volume first drain and meant valves did not re-open until approximately 14 minutes after the scram was reset due to excessive leakage past an air supply/exhaust valve (cause not described). (LER# 9315)
8/01/93	None Turb.	Power hold at 45% to repair the controls of the turbine control/steam bypass systems.
10/14/93	Forced Turb. Relay	Routine testing of the turbine was being performed when a turbine trip and reactor scram from 95% power occurred due to the failure of relay contacts to open per design. The failure of the K15-1 relay contacts was not known. During troubleshooting, the failure of the relay could not be recreated. The relay was replaced. (LER# 9324) Reactor at 95% power. While performing surveillance test on main turbine thrust bearing wear detector turbine trip, a reactor trip occurred, caused by a turbine trip. This caused a loss of system and resulted in a reactor trip. The relay (k-15 in the turbine control panel that should bypass this trip did not energize, which in turn did not bypass the thrust bearing wear detector turbine trip. Cause of relay failure is unknown. Relay is part of turbine control unit. Test was run several times to try to duplicate problem, but the problem could not be duplicated. A extensive exam of relay and socket is being performed. Relay was replaced like-for-like. Relay functionally tested. Test satisfactory.
12/6/93	None Fail SB&PR Connection	During troubleshooting of another problem, received a steam bypass pressure control module 3 load following regulation error. This error prevented the capability of transferring control between like channels. The plant was in process of shutting down for a refuel outage, and no problems were occurring on the selected pressure control channel. The transfer failure was caused by two problems. The connector feeding the pressure set point adjuster card had an open on pin 15, which prevented energizing a relay that closed a contact to short pins 1 and 9. This open contact placed the system in a “load following” mode. The load following circuitry is not used or tuned but is active in the circuit. The untuned load circuitry caused a mismatch in the control signal and initiated a load regulation error and prevented transferring control to the other channel. The cause of the open connection is unknown, but suspect dirty contacts. The j113 connector was removed, cleaned, and reinstalled. Temporarily, the module 3 load following error set point was increased to prevent initiating a lockout from a load following mismatch error. A modification was submitted to remove unused circuitry in the system and jumper pins 1 and 9 on the pressure set point adjuster card. The steam bypass and pressure control system was transferred several times with no problems.
4/29/95	Forced Fail TSI Probe	The turbine was taken off-line due to problems with bearing vibration indication. A vibration probe was replaced.
6/06/96	Forced Turb. PwrSup Fail Design	While the plant was at 100% power, turbine combined intercept valves and one turbine stop valve began to close unexpectedly, causing a pressure rise that caused all four MSR relief valves to lift. This caused a reduction in turbine load, followed by a reactor FW pump trip on low suction pressure. The control valves partially closed to control throttle pressure. When the MSR relief valves reseated, reactor pressure began to increase, and the APRM upscale alarm lights illuminated. A manual scram was then initiated. The root cause was determined to be recently replaced EHC power supplies, which were inadequate for their intended purpose. Even though the power supplies were configured such that a single failure should not affect the bus, a failed power supply caused bus voltage to degrade. (LER# 9612)

APPENDIX D
EVENTS FOR PWR PLANTS WITH MARK II EHC

DATE	TYPE	NARRATIVE
1/07/85	Forced TSI Noise TurbVib	The operators were reducing load in preparation to remove a heater drain pump from service when a high vibration turbine trip from 50% occurred due to spikes generated by Turbine Bearing #1 Vibration Detector. Also actuated were a FW isolation, AFW actuation, and SG blowdown isolation. To prevent additional unnecessary challenges of the RPS, the high vibration turbine trip circuitry was modified to provide an alarm function vice a trip function. (LER# 8502)
11/11/85	Forced Gen Vibration Fatigue TempSwt	A turbine trip / reactor trip from 100% power occurred as a result of high stator cooling water temperature when the stator cooling water temperature control valve inadvertently stroked to full bypass, diverting flow around the heat exchangers. A FW isolation, AFW actuation, and SG blowdown isolation occurred per design. The valve stroked to the full bypass position due to fatigue failure of the calibration link in its temperature controller as a result of vibration. A turbine runback signal was initiated but did not actually occur due to a random relay failure in the EHC control circuitry. This failure resulted in the turbine trip / reactor trip. (LER# 8549)
2/22/86	Forced Turb. Fail	A reactor trip from 100% power, turbine trip, FW isolation, AFW actuation, SG blowdown and sample isolation occurred as a result of a SG low-low water level condition. The cause of this event was a circuitry failure in the main turbine EHC system that caused the main Turbine Control Valves to close during performance of a routine turbine test. The rapid reduction in steam flow caused a SG level shrink and a reduced speed demand signal to the FW pump turbines that caused a reduction in FW flow to the SGs. This resulted in a decreasing water level in the SGs and a low-low SG level reactor trip. (LER# 8607)
4/19/86	Forced Gen Proc PE	A reactor trip from 16% power, FW isolation, AFW actuation, and SG blowdown isolation occurred as a result of a low level in SG A. The low SG level occurred as a result of SG level oscillations immediately after paralleling the main generator to the grid. The trip was caused by operator error in synchronizing the main turbine generator at an excessively high initial load that led to SG level oscillations. A contributing factor was the mismatch between demand signal and actual load. (LER# 8613)
7/26/86	Forced Turb. Adjstmnt	A reactor trip, FW isolation, and AFW actuation occurred from 73% power as a result of a turbine trip during the performance of the mechanical trip piston test surveillance. The mechanical lockout solenoid valve had de-energized due to a premature reset signal initiating an overspeed turbine trip signal that tripped the turbine. The root cause was the trip finger or limit switch actuating mechanism settings. (LER# 8627)
11/21/86	Forced	Spurious turbine trip during startup from refueling.
11/26/86	LoadRed Turb.	Turbine runback possibly due to EHC problems.
11/29/86	LoadRed Turb. LimitSwt Fail	Turbine trip limit switch position lost during testing. Load was reduced to 50% power.
12/05/86	LoadRed Turb.	Load reduction due to turbine instrumentation problems.

DATE	TYPE	NARRATIVE
1/31/87	Forced Turb. Proc	A reactor trip occurred on a High Flux-Low Power Reactor Trip signal. Control room personnel were in the process of bringing the turbine-generator on-line with the unit at approximately 13% power. Due to a high (10%/minute) loading rate that was automatically selected when the generator breaker closes, the turbine demand resulted in a sharp decrease in RCS average temperature. In an attempt to maintain temperature, reactor power was increased. Reactor power reached the 25% set point before control room personnel were able to block the High Flux-Low Power Reactor Trip signal. The operating procedure for the turbine-generator did not specify the need to change the loading rate prior to placing load on the turbine. (LER# 8706)
2/02/87	LoadRed Turb.	Power hold due to turbine control problems.
3/17/87	LoadRed Turb.	Load reduction due to a loss of turbine emergency trip system pressure.
5/28/87	Forced Elec VoltSwt Fail	A turbine building fan breaker malfunction caused a loss of power to 480 volt motor control center PG11K. This caused a loss of backup power to the main turbine EHC system, which caused closure of the main Turbine Control Valves. This caused SG level shrink to the low-low level set point, resulting in a reactor/turbine trip from 100% power, FW isolation, AFW actuation, and SG blowdown and sample isolation. Later, when attempting to reclose the reactor trip breakers (RTBs), the RTBs reopened and a FW isolation occurred because a nuclear instrumentation Negative Rate Trip signal had not been reset from the earlier trip. The failure of the turbine EHC system was traced to the failure of the voltage sensor that monitors the output of the permanent magnet generator. (LER# 8722)
7/28/87	LoadRed Turb. CardNS	Short outage continuation during startup from a reactor trip due to a loss of turbine load acceleration.
7/28/87	Forced Turb. Proc	The unit was operating at 100% power when an automatic reactor trip occurred as a result of the emergency trip hydraulic fluid pressure transmitters sensing a low pressure. The root cause of the event was improper technique employed by an instrument technician during testing. There was no formal procedure for this work activity, however, the system engineer had issued verbal instructions. The improper testing technique caused a false power load unbalance signal that caused the turbine control and intermediate Stop Valves to close. A contributing cause to the event was an inadequate technical review by the system engineer. The reactor trip initiated a turbine trip, FW isolation and Auxiliary FW actuation. (LER# 8750)
11/05/87	Forced TSI Proc TurbVib	The unit was operating at 100% power when an automatic turbine trip and reactor trip were generated by a spurious turbine vibration monitor actuation. FW isolated and Auxiliary FW actuated after the trip as designed. The cause of the event was inadvertent actuation of a vibration monitor. A mechanic had been caulking bolts near a turbine bearing housing while laying on the cabling for the vibration monitor. The root cause of disturbing the cabling was procedural inadequacy. Contributing causes for the event include a lack of labeling to identify the vibration monitors and cabling as potential trip devices, and failure of supervision to identify potential problems to personnel performing work. (LER# 8763)

DATE	TYPE	NARRATIVE
2/13/88	Forced Turb. Spurious PE	A reactor trip occurred from 100% power during turbine surveillance testing. The mechanical trip piston had failed to reset. Per procedure, a jumper was installed in the EHC cabinet to allow resetting the turbine test circuit and completing the test. The clip of the jumper slipped loose, shorting the circuit to ground, causing the turbine/reactor trip. By design, a FW isolation and AFW actuation occurred. Following the trip, RCS temperature continued to decrease due to excessive steam loads. The operators were not continuously cognizant of the decreasing RCS temperature. Steam pressure decreased to 615 psig and a Safety Injection and Main Steam Line Isolation were actuated. (LER# 8804)
2/17/88	Forced Turb. Solenoid Fail	The turbine was taken off-line due to a turbine trip solenoid failure.
3/21/88	LoadRed Relay Turb. Fail	Power hold due to turbine runback circuit relay failure.
5/02/88	Forced Spurious TPL Turb.	An automatic reactor trip occurred from 99% power on SG B low level. The Main Turbine Throttle Pressure Limiter spuriously actuated, causing the main Turbine Control Valves to close. The loss of steam demand caused the SG level to shrink to the low level reactor trip set point. A FW isolation and AFW actuation were received by design. During restoration from the trip, the FW isolation was reset per procedure. An operator reopened the reactor trips and received a FW isolation signal. The operator failed to recognize that reopening the reactor trip breakers would result in reinitiation of the FW isolation signal. (LER# 8807) LER 483-88007-00 On 5-2-88 at 1536 CDT, an automatic reactor trip occurred on b steam generator (s/g) low level. The main turbine throttle pressure limiter (TPL) spuriously actuated, causing the main Turbine Control Valves to close. The loss of steam demand caused the s/g to shrink to the low level reactor trip set point. A feedwater isolation (FWIS) and auxiliary feedwater isolation were received by design. The licensed operators recovered from the trip via plant procedures. For this event, the plant was in mode 1, power operations at 99% reactor power. Reactor coolant system (RCS) temperature was 588 degrees f and RCS pressure was 2235 psig. During restoration from the trip, the FWIS was reset per procedure. At 1736, with the plant in mode 3, hot standby, a licensed operator re-opened the reactor trip breakers and received a FWIS. The operator failed to recognize that re-opening the reactor trip breakers after resetting the FWIS would result in a reinitiation of the FWIS. The TPL was bypassed via a temporary modification. Permanent elimination of the TPL circuit is under evaluation. Progressive discipline was initiated with the licensed operator involved. This event was discussed with shift supervisors, and training for the licensed operators will be conducted on this event during the next requalification cycle.
5/28/88	Forced Turb. Relay Fail	Load reduced to 96% due to a loss of MSRs #1 and #2 caused by a main turbine pressure switch failure.

DATE	TYPE	NARRATIVE
8/27/88	Forced Turb.	The Main Generator was synchronized to the grid and loaded to approximately 80 MWe. As turbine-generator load was increased, a RCS cooldown began and pressurizer level began to decrease due to the increase in steam flow through the turbine. Steam demand increased to a level greater than that of existing reactor power. A reactor operator increased dilution flow in an attempt to raise temperature and started the third charging pump in an attempt to increase pressurizer level. Also, Control Element Assembly (CEA) group 5 was withdrawn and the load on the Main Generator was decreased to 45 MWe in an attempt to mitigate the cooldown. As a result of the dilution and CEA withdrawal, reactor power increased to the point of swapover for the FW regulating valves. The isolation valves were shut for the economizer FW regulating valves and all FW flow was lost. The downcomer valves were reopened and FW flow reestablished. The event appeared to be stabilized when the B FW pump tripped on high discharge pressure. SG level decreased and the reactor tripped. (LER# 8824)
10/30/88	Forced Elec PwrSup Fail	LER 289-88006-00 At 8:49 a.m. on October 30, 1988 the main turbine tripped to manual with a coincident array of about 8 alarms. Generated megawatts were rapidly decreasing and the main steam safety valves began to lift. Within 4 seconds of the initiation of the event, the reactor tripped on high RCS pressure. The post trip response was normal. Two conditions required operator response. A main steam safety valve did not completely reseat. Operators lowered the steam header pressure control set point about 50 psig and the valve reseated. In addition, the main feedwater startup control valve did not control in automatic and required operator action. This second problem has been corrected by retuning the ICS modules. The reactor trip was caused by rapid closure of the main Turbine Control Valves. The closure initiation is attributed to be a result of an erroneous signal being generated within the EHC. Investigation revealed an erratic power supply that required replacement along with a relay in the #4 intercept valve test circuitry within the EHC cabinets. This relay problem was not considered to be related to the root cause of the event. It is believed that the erratic power supply is the most likely initiator of the event.
1/23/89	Forced TSI TurbVib Spurious	A reactor trip from 100% power occurred as a result of a high bearing vibration main turbine trip. A FW isolation signal, an auxiliary FW actuation signal, and a SG blowdown and sample isolation signal occurred as designed following the reactor trip. The cause of the trip was determined to be a spurious signal in the vibration monitoring circuitry that incorrectly indicated high vibration on the main turbine #7 bearing. The root cause of the signal was not known. (LER# 8902)
5/15/89	Forced Turb.	Load reduction due to a turbine control circuit problem—also on 5/16/89.
6/09/89	Forced TSI TempSwt Drift	The turbine tripped at 1636 hours and 1648 hours on high exhaust hood temperatures caused by temperature switch set point drift. An emergency high FW heater level alarm occurred and the F and G low pressure heaters isolated. The emergency high level was suspected to be caused by steam condensing in the level instrument lines faster than the lines could drain due to low temperature and heat input during low power or turbine off-line conditions. FW heater bypass valve 2CM81 failed to open in response to the heater isolations because the valve's MCC was not properly seated against the bus bars. The condensate booster pump tripped on low suction pressure, causing FW pump B to trip (FW pump A was already tripped). Turbine bypass valve (generator load rejection bypass valve) 2CM83 failed to open on low condensate booster pump suction due to instrument air being isolated to the valve operator and malfunction of the valve controller due to dirty inlet ports. AFW automatically actuated and SG blowdown and nuclear sampling isolated. Reactor power was reduced from 11% to 3% power so that AFW pumps could maintain SG levels. (LER# 8915)

DATE	TYPE	NARRATIVE
10/17/89	LoadRed Turb. Fail PLUsensor	Load reduction to replace a power/load unbalance transducer in the turbine control cabinet.
11/29/89	LoadRed Turb. Connection Fail	A rapid reduction in turbine load occurred, resulting in increased temperature and pressure in the reactor coolant system (RCS), causing the reactor to trip from 100% power on high RCS pressure. The rapid load reduction was the result of EHC action. Minor calibration drift was found on the power load unbalance circuitry (the drift would not have caused the transient). Another possible cause was a power supply transient. Bench testing of the power supplies indicated a problem with one of the supplies; however, due to the redundant supply, this was not considered to be the cause of the event. The power supplies were replaced prior to unit startup. The probable cause of the event was a loose shield wire on the input to the speed error circuit from the turbine primary speed sensor. The loose connection may have been disturbed by opening and closing of the cabinet doors. The electrical malfunction light on the EHC panel was lit due to a failed meter relay for the 3 KHz oscillator. Inspections were being performed at the EHC cabinet to check for additional malfunctions. The inspections at the cabinet may have contributed to the event. (LER# 8903) LER 289-89003-00 At approximately 0806 hours on November 29, 1989, a rapid reduction in turbine load occurred. This rapid reduction in load resulted in increasing temperature and pressure in the reactor coolant system causing the reactor to trip on high RCS pressure within about 4 seconds. The reactor protection system functioned correctly and operator response was appropriate. The post trip response was normal. Main steam header pressure was reduced to reseat a main steam safety valve (ms-v-21a). Level control for b otsg was considered sluggish and the feedwater valve was controlled manually. These actions are in accordance with procedures and training. The rapid load reduction was the result of EHC action. The power load unbalance circuit that protects the turbine from overspeed and the speed error circuit were suspected because either of these circuits can result in rapid control valve closure. The function and calibration of these circuits were checked. Minor calibration drift was found. The drift was not abnormal and would not have caused the transient. A loose shield wire was found on the input to the speed error circuit from the turbine primary speed sensor. It is postulated that the loose connection was disturbed by opening and closing the cabinet doors. This was determined to be the probable cause.
6/28/90	Forced Elec PwrSup Drift	Unit 2 was operating in Mode 1 at 87% power when an MSIV failed causing operators to manually trip the reactor. Main FW isolated and Auxiliary FW started as the unit stabilized in Mode 3. The root cause of the MSIV failure was the failure of an O-ring that seals the connection of the non-pump side manifold assembly to a boss on the actuator cylinder. Possible contributing causes to the O-ring failure included: a slight misalignment of the cylinder boss and manifold assembly, a small low spot at the edge of the actuator cylinder boss, and a possibility that the O-ring may have been pinched in installation. Equipment malfunctions observed following the reactor trip included: a failure of the +22 VDC power supply for the turbine EHC system due to the supply voltage drifting out of adjustment, and a cycling of the atmospheric relief valves for SG 1 and 2 at a pressure below their set point for an unknown reason. (LER# 9008)

DATE	TYPE	NARRATIVE
6/30/90	Forced Elec PwrSup Fail	Prior to this event, Unit 2 was in Mode 1 at 18% power and was experiencing delays in rolling the turbine and synchronizing the generator to the grid. The shift superintendent (SS) allowed reactor power to increase due to xenon burnout and, because synchronization appeared imminent, chose to proceed with the transfer of SG level control to the main FW regulating valves. Further delays in getting switching orders from the Control Center caused SG levels to reach the high-high set point, inducing a FW isolation and turbine trip. Operators then manually tripped the reactor (at 8% power) as SG levels rapidly fell. Main FW isolated and Auxiliary FW started as the unit stabilized in Mode 3. A manual steam line isolation was initiated to limit cooldown. The initial delays were due to troubleshooting and repair of a problem with the turbine intermediate Stop Valves and a failure of the 24 VDC permanent magnet generator power supply for the turbine control system. The turbine intermediate Stop Valves would not stay open because the load set potentiometer was saturated. The root cause was the permissible decision by the SS to risk operating with the SG levels in manual control with the turbine-generator unloaded. (LER# 9009)
8/22/90	Forced Elec	LER 443-90022-00 On August 22, 1990 at 9:19 am, EDT, while in mode 1 at 100% reactor power, a turbine-generator trip with reactor trip occurred. The trip was initiated by an apparent loss of voltage on the electrohydraulic control (EHC) 24 volt DC bus during troubleshooting activities. A main feedwater isolation also occurred subsequent to the reactor trip. A work request was initiated to perform circuit checks in the early valve actuation (EVA) circuitry due to inconsistent operation of the EVA's test interlock light located on the main control board (MCB). subsequent to initial testing at the MCB, it was decided to continue the testing locally at the EHC cabinet. Two test leads were used to simulate the test signal and to supply 24 volt DC power to the EVA circuit. After the second application of the test leads, a voltage drop occurred on the 24 volt DC trip bus resulting in a turbine-generator trip with reactor trip. The root cause for the loss of voltage on the EHC 24 volt DC bus could not be conclusively determined, although a contributing factor was the troubleshooting activity associated with the EVA circuit. Personnel error in applying the test leads has not been ruled out but is considered unlikely; will carefully evaluate all future EHC maintenance activities performed during power operation in order to minimize challenges to plant systems. Additionally, as part of our trip avoidance program, each EHC maintenance activity during power operations will be reviewed on a case work in the field. With respect to feedwater isolation, a design change has been initiated to install an electronic circuit that will eliminate the effects of the pressure pulses on the steam generator level trip signals.

DATE	TYPE	NARRATIVE
2/12/91	SwitchGear Forced Proc	LER 443-91001-00 On February 12, 1991, at 8:22 a.m. EST, a turbine-generator trip with a reactor trip occurred while the plant was at 100% power. The trip was initiated by a loss of electrohydraulic control (EHC) system pressure. A main feedwater isolation and an emergency feedwater actuation also occurred subsequent to the trip. Prior to the event, 480 volt AC unit substation ed-us-14 was cross connected to unit substation ed-us-21 in preparation for various electrical maintenance tasks on the primary breaker, secondary breaker and transformer for ed-us-14. Approximately twenty-five minutes following the cross connection, the secondary breaker for ed-us-21 tripped due to the energization of two large cyclic loads, the turbine building crane and the guardhouse megatherm tank heaters. Consequently, power was lost to both EHC pumps causing a loss of EHC system pressure that resulted in a turbine-generator trip with a reactor trip as designed. The root cause has been determined to be an inadequate procedure. A contributing cause was inadequate training. To prevent recurrence, operating procedures, maintenance repetitive task sheets and planning and scheduling procedures will be revised to provide additional controls to ensure that the overall connected load is formally evaluated and controlled prior to cross connecting unit substations. The lessons learned from this event will be discussed with all operating crews. Additionally, a training development recommendation (TDR) will be written to address failure mode and consequence thought processes during abnormal system alignments. This is the first event of this type at the station.
5/16/91	None Turb. Relay Fail Open	During full power operation, operators noticed the main steam Turbine Control Valves would not respond during the weekly surveillance test. During a normal test each Turbine Control Valve closes in-turn while the other valves open to maintain steam flow to the turbine. The subsequent investigation found a failed stage pressure feedback transfer control relay (piece part of the electrohydraulic controller); the relay contacts would not close. System operability was degraded; operators could not meet technical specification requirement to test Control Valves. There were no significant plant effects; repairs were accomplished before plant down-power action statement implemented. The cause of the relay failure is thought to be normal wear-out due to aging. The failed control relay (k-7 on circuit board 1l2-b004) was replaced in-kind. The Turbine Control Valves were then tested and declared operable.
9/3/91	AtSD Elec PwrSup Fail Wearout	The unit was in hot standby. During a plant start up the turbines permanent magnet generator +22 VDC power supply (PS) (piece part) for the electrohydraulic control (EHC) system, failed causing control room and local alarms. The failure was immediate. The system function was lost and the plant was prevented from starting up. The cause of the failure was the +22 VDC power supply. A replacement power supply was not available, therefore the original PS was troubleshot. Troubleshooting found shorted capacitors and diodes internal to the PS. The cause of the failure is unknown, the suspected cause is due to the age of the PS. The original PS was reworked and tested satisfactorily and subsequently re-installed into the EHC cabinet. Following satisfactory retesting the unit was successfully started up

DATE	TYPE	NARRATIVE
9/27/91	Forced Proc Turb.	The reactor tripped from 13% power on high SG pressure during turbine valve tightness testing due to improper and inadequate procedural guidance. Main FW isolated and emergency FW auto-initiated due to low SG levels, and post trip plant response was normal. (LER# 9103) LER 289-91003-00 On September 27, 1991 during plant shutdown for the 9r outage reactor power was stabilized at 13% to support completion of turbine valve tightness testing and a special test of the turbine overspeed mechanical trip d vice. The turbine load limit control was turned to the minimum setting to close the Turbine Control Valves and begin the tightness test while the Stop Valves remained open. The Control Valves closed as expected and the turbine decelerated indicating the leak tightness of the valve. After about seven minutes of deceleration, the turbine speed was 1200 rpm. In accordance with procedure, the cro selected the fast acceleration r ate on the turbine control panel and turned the load limit control to maximum setting. The turbine control valves immediately started opening rapidly and otsg pressure began dropping rapidly. Approximately ten seconds later at 18:37, the turbine tripped on overspeed. Subsequently, main feedwater was isolated to both otsgs due to low otsg pressure and both emergency feedwater trains were auto initiated due to the low otsg levels. The reactor tripped at 18:38 on high pressure. Normal feedwater flow to the otsgs was re-established and post trip response was considered normal. The NRC was notified in accordance with 10 CFR 50.72 (b) (2) (ii).
10/27/91	Forced Lightning Gen	Prior to this event, Units 1 and 3 were at 100% power, and Unit 2 was in refueling. A grid perturbation caused by a lightning strike on a substation feeder line resulted in reactor trips at both units when reactor power increased beyond the Core Protection Calculator Variable Overpower Trip set points. Immediately following the trips, Safety Injection Actuation System and Containment Isolation Activation System actuations occurred on low pressurizer pressure. All safety system components actuated as designed in both units, and they were stabilized in Hot Standby. Borated water was injected into the reactor coolant system of Unit 1, but not Unit 3. The turbine EHC power/load unbalance protection circuitry in all three units was modified to better respond to a momentary grid disturbance. (LER# 9110) LER 528-91010-00 On October 27, 1991, at approximately 0722 MST, Units 1 and 3 were operating at approximately 100% power when a grid perturbation caused the main turbine control system to fast close and immediately reopen the Turbine Control Valves (TCVs). The momentary reduction in steam flow caused the steam bypass Control Valves in Units 1 and 3 to quick open. A reactor power cutback occurred in Unit 3, but not in Unit 1. Reactor trips in Units 1 and 3 occurred when reactor power exceeded the core protection calculator variable overpower trip set points. Immediately following the trips, safety injection actuation system (SIAS) and containment isolation actuation system (CIAS) engineered safety feature actuation system actuations occurred on low pressurizer pressure. All safety system components actuated as designed in each unit. By approximately 0805 MST on October 27, 1991, the plants were stabilized in mode 3 (hot standby). The cause of the event was determined to be the expected plant response to a unique combination of circumstances. The event was precipitated by a grid fault resulting from a lightning strike on a substation feeder line. The fault that occurred was different from previous grid disturbance events (i. E., fault without ground). The generator output current decreased triggering a momentary power/load unbalance turbine protection actuation. This submittal also provides a special report in accordance with tech spec 3. 5. 2 action b.

DATE	TYPE	NARRATIVE
4/8/92	None Turb. VPCard Fail	Main steam Turbine Control Valve 3 was acting erratically-oscillating with no apparent demand. The failure was found by control room operators through system abnormalities and caused a degraded train effect due to the erratic operation of the valve not controlling steam flow to the turbine properly. The failure had no impact on plant status. (mwo 19200753) the cause of the valve oscillating was due to a defective position driver board in the electrohydraulic control cabinet, which was sending erratic signals to the valve causing it to oscillate. Investigation revealed that several of the Control Valves were experiencing the same problem and troubleshooting showed that the position driver or control board in the electrohydraulic control cabinet was the source of the problem. The root cause of the board failure is unknown. Replaced the defective position control board with one removed from Unit 2 that was out of service for refueling at the time, verified proper operation of the Control Valves and returned it to service.
6/18/92	None Turb. CardNS Fail	A control room alarm indicated that one of the redundant outputs of the main turbine instrument and control system controller circuit boards (piece parts of the electrohydraulic control (EHC) electronic controller) for the main Turbine Control Valve "3" had failed with no output. The main steam system was in service and unaffected due to redundant output functioning properly. The plant was operating at 100% power and operations were unaffected. The root cause of the circuit board failure was not determined. The failed circuit board was replaced with a like kind. The EHC electronic controller was returned to service following a functional test.
6/29/92	LoadRed Turb. LdLmtcrd Fail Wearout	Unit was at power operation and the main steam system was in service when control room shift operator noted a 200 megawatt electrical load shed for no apparent reason. The load shed occurred with the system in the manual mode and stabilized when placed in standby. The condition resulted in a degraded main steam system because the turbine/generator was operable with less than desirable output. The plant was degraded because the failure resulted in reduced power operation. Troubleshooting under system engineer direction led to a faulty load rate/load set limit card within the electrohydraulic control cabinet. The component performs switching actions to impose the necessary rate of change and level limitations upon the load set analog signal to establish the load reference signal voltage. Cause of failure unknown. I & c technician suspected a faulty integrator circuit. Suspect card failed due to normal aging. Faulty card was replaced with new card and retested satisfactorily. No additional problems noted.
9/20/92	Forced TSI Relay Fail	The lockout relay contact in the main turbine thrust bearing wear detector test circuitry failed during thrust bearing wear detector testing, resulting in a turbine trip and a reactor trip from 100% power. FW isolation and auxiliary FW actuation occurred. (LER# 9210) On 9/20/92, during the performance of a weekly preventative maintenance test of the main turbine thrust bearing wear detector, the plant experienced a turbine trip. The turbine trip subsequently caused an interlocked automatic reactor trip, feedwater isolation and auxiliary feedwater actuation. The plant was at full power with the main steam and the reactor coolant systems at normal operating pressure and temperature. Further investigation revealed that the lockout relay contact in the main turbine thrust bearing wear detector test circuitry failed (piece part of the electrohydraulic control power unit). Root cause of the lockout relay failure is unknown. The relay had no obvious signs of damage and the failure was not repeatable. A possible cause is a defective circuit. The lockout relay was replaced with a like kind one. Appropriate retests were performed and the unit returned to service. A review of the current turbine test program was performed to evaluate the risk of a failure during testing causing a trip versus the reliability benefit gained from the testing. Test frequencies will be adjusted accordingly.

DATE	TYPE	NARRATIVE
11/20/92	Forced Elec Spurious	Low voltage on the 120V bus that supplies control power to the EHC system caused the turbine throttle pressure limiter to indicate low steam chest pressure and close the Turbine Control Valves. The reactor tripped from 100% power on low-low SG level. No specific cause for the degraded voltage condition could be found. Following the trip, AFW actuated on low SG level, and FW isolated on low RCS Tave. (LER# 9229) LER 423-92029-00 At 0403 on November 20, 1992, with the plant in mode 1 at 100% power, a turbine load rejection transient resulted in a reactor trip followed by a turbine trip. The Turbine Control Valves closed coincident with an electrohydraulic control (EHC) trouble alarm and a low voltage alarm on the regulated 120 volt instrument buses. While all events are consistent with the fact that degraded voltage was being supplied to the EHC system, no specific component could be found that caused the degraded voltage. A management review of this condition and actions to minimize impact in the event of recurrence was conducted before startup was authorized. The auxiliary feedwater system started due to the low-low level in one steam generator. A feedwater isolation occurred due to low reactor coolant system average temperature after the reactor trip. No other engineered safety feature (ESF) signals were initiated or required and the event posed no significant hazard to the health and safety of the public.
2/01/93	LoadRed Turb.	Stopped power ascension at 43% power due to problems with turbine controls and reactor power cutback system interface.
2/07/93	Forced Elec PwrSup Wearout Fail	Turbine control problem delays startup from feedwater pump trip outage. While the unit was in hot standby, the main turbine failed to maintain rated speed during performance of the presynchronization testing. Investigation found the permanent magnet generator (PMG) power supply (a piece part of the main turbine electrohydraulic control (EHC) cabinet) was producing low output voltages, resulting in the turbine Control Valves closing. When the PMG breaker was closed, the turbine began losing speed. The output on the PMG power supply was 22. 91 VDC. After being set to 23. 11 VDC, it drifted back to 22. 91 VDC. The power supply could not be adjusted to produce proper output. The main steam system was degraded. Since the system was in tests prior to unit restart, the plant was not affected. Suspect the cause of failure was due to defective electronic piece parts in the PMG power supply as a result of aging. The PMG power supply was replaced with a new like kind power supply. Monitoring during synchronization testing found the EHC functions returned to normal.

DATE	TYPE	NARRATIVE
3/31/93	Forced Elec PwrSup Cmpnt Fail	A capacitor failure in one of the EHC power supplies caused noise to EHC solenoids resulting in slow closure of all Turbine Control Valves. Turbine Control Valve closure caused a reactor trip from 100% power on low-low SG level. AFW actuated on low SG level and FW isolated on low RCS temperature coincident with the reactor trip. Following the trip, one of the SG safety valves failed to reseat due to an incorrect lower adjustment ring setting. After the event, seven other safety valves were found to also have incorrect lower adjustment ring settings. The cause of the incorrect settings was unknown. (LER# 9304) With the plant at 100% power, number 2 main steam stop valve (1 of 4 valves) went shut for no apparent reason. The closure resulted in loss of water level control in the “b” steam generator (1 of 4 steam generators). Within seconds, a reactor trip was received due to low-low water level in “b” steam generator. The reactor trip was immediately followed by a turbine trip. Troubleshooting by I&C personnel indicated the cause of problem to be a failed 22 VDC electrohydraulic control (EHC) power supply. (a piece part of EHC control circuit) the failed power supply had an 11 volts peak-to-peak ripple on its output. Root cause of the failure is unknown but suspect aging of the electrolytic filter capacitors. (exact cause to be determined by vendor) the failed power supply was replaced with an “in kind” spare. (as a precaution, a time delay relay on one of the EHC circuit boards was also replaced) additionally, all other EHC power supplies were checked for proper operation. The EHC system was tested for proper operation per applicable plant procedures and returned to service. LER 423-93004-01 At 0103 on March 31, 1993, with the plant in mode 1 at 100% power, a turbine valve closure resulted in a reactor trip followed by a turbine trip. Turbine valve closure was the result of a faulty power supply in the electrohydraulic control (EHC) system. With the exception of a steam generator code safety valve not completely reseating, the plant responded normally to the transient. Extensive trouble shooting determined that a power supply in the EHC system was faulty and caused the turbine valves to close. The faulty power supply was replaced. As action to prevent recurrence, the power supplies in the EHC system will be replaced or refurbished on a 10 year period. Subsequent investigation determined that the steam generator safety valve that did not completely reseat had an incorrect lower adjustment ring setting. Additional inspection revealed that 7 other safety valves also had incorrect settings. Three of these valves indicated that they lifted and reseated during the transient. The other four valves did not open. The root cause of the improper settings was inadequate work control by the vendor. Crosby valve and gage company, who performed maintenance on the safeties, conducted an investigation and determined that their personnel inadvertently used the wrong procedure to set the lower adjustment rings.

DATE	TYPE	NARRATIVE
8/14/93	None Elec VoltSwt Fail	With plant at full power, an alarm in control room indicated a problem with inverter 5. At the same time, the Turbine Control Valves closed and steam generator levels dropped rapidly resulting in a plant trip. The specific device that physically created the condition that resulted in the reactor trip could not be determined. Later, analysis of potential causes for the condition resulted in a decision to replace the EHC power transfer switch voltage sensor at first opportunity. The power transfer switch is a piece part of the EHC control panel that functions to automatically transfer EHC power source between house power and PMG power. During the next outage, the power transfer switch voltage sensor was replaced with and "in kind" spare. Bench testing of the removed device revealed it to be defective in that it would not produce the power transfer in all cases as designed. (the new voltage sensor was tested in the same exact manner before installation and found to perform properly) the exact cause of the failure is unknown but suspect aging/cyclic fatigue of one or more electrical or electronic components that comprise the instrument.
9/21/93	AtSD Elec PwrSup Fail Defect	The plant was shut down in a refueling outage. Instrument and controls personnel performing routine scheduled maintenance in the EHC panel (electronic control section) noticed that the 24 VDC low voltage alarm light was illuminated. The technicians also observed a large momentary drop in the 24 VDC supply voltage when a "lamp test" was performed. With the plant shut down there was no effect on plant operability but the EHC system was degraded because the reliability of the 24 VDC power supply (a piece part) was in question. Troubleshooting revealed that the power supply voltage would droop greater that 10 VDC during the lamp test power demand surge. This was considered excessive. The exact cause of the problem is unknown but suspect a manufacturing defect because the power supply was almost new, having been in service only a few days. The power supply was replaced with an "in kind" spare. The new power supply was thoroughly tested to ensure it did not exhibit similar characteristics and returned to service iaw plant procedures. The removed power supply will be returned to vendor for warranty replacement.
9/26/93	AtSD Fail Relay Turb.	The plant was shut down in a refueling outage. Instrument and controls technicians performing scheduled preventive maintenance calibration work on instrument loops associated with the EHC panel (electronic control section) found the combined intermediate valve (intercept valve) dual voltage comparator card was inoperable. With the plant shutdown, there was no effect on plant operability. EHC system operability was degraded because this comparator (a piece part of EHC) would no longer provide a logic signal to allow fast closing of intercept valves. Troubleshooting revealed the output contacts of a relay on the comparator circuit card were not changing state. The exact cause of the failure is unknown but the technicians think it was just normal wearout due to aging and or cyclic fatigue. The faulty relay was replaced using the relay from the other voltage comparator circuit on the board. (the second circuit on this particular circuit card is not used) after repairs were completed, the calibration process on the instrument loop was continued in accordance with plant procedures and completed with no other problems.

DATE	TYPE	NARRATIVE
10/7/93	Forced Turb. Valve Fail	Unit was at power and the main turbine (MT) was in operation. While performing the weekly electrical trip test on MT, the malfunction light came on indicating a problem. The system function to provide electrical turbine trip was lost. The system could not be removed from test and the electrical lockout solenoid valve was bypassing the electrical trip function. Operations reduced plant power and removed the MT from service. Troubleshooting found that the electrical trip valve operating rod was not moving while attempting to reperform the test indicating a possible problem with the electrical trip solenoid valve (ETSV) or electrical trip valve (ETV) (piece parts of EHC power unit) cause of the failure was unknown. No obvious problems were found with the ETV during inspection. The ETSV was replaced with an ETSV from Unit 1. The ETV was disassembled, inspected and rebuilt. The suspect ETSV was sent to engineering for failure analysis. The electrical trip test was performed satisfactorily.
10/09/93	Forced Turb. Solenoid	The turbine was taken off-line for repairs of the main turbine emergency trip solenoid valve.
10/14/93	AtSD Fail VCCard Turb.	The plant was shut down in a refueling outage. Instrument and controls technicians performing scheduled preventive maintenance calibration work on instrument loops associated with the EHC panel (electronic control section) found the intermediate pressure dual voltage comparator card could not be properly calibrated. With the plant shutdown in a refuel outage, there was no effect on plant operability but the EHC system operability was degraded because this bistable (a piece part of the EHC panel) permits the fast closing of the Combined Intercept Valves. Troubleshooting revealed the bistable set point was unstable and also over-sensitive to small environmental temperature changes. The exact cause of the failure is unknown at this time but suspect the circuit is defective due to the aging and/or cyclic fatigue of one or more components on the circuit card. The circuit card was replaced with an “in kind” spare. The new circuit card and its associated instrument loop was calibrated per applicable plant procedures and returned to service. The failed circuit card will be returned to vendor for repair.
2/10/94	None Turb. POT Wearout Fail	The unit was at power and when operation's personnel decreased turbine load using the load limit potentiometer (a piece part of the main turbine electrohydraulic electronic controller (EHC)) an immediate increase of about 15 megawatts occurred on the main generator output followed by an equal decrease in power. The EHC controller was degraded, main turbine main steam pressure oscillated as generator output power cycled. The main generator and the plant were subsequently stabilized and remained in automatic control and operation. The cause of the failure was due to wear on the load limit potentiometer (pot). Troubleshooting found a spot on the pot that had “flattened” due to it being the position the pot is in during most of its use. A condition report was initiated to evaluate the cause of the power spikes during main turbine load adjustments. The load limit pot was replaced with on of like kind obtained from the warehouse. A functional test was performed in accordance with system engineering's instructions. The functional test was successful.
3/26/94	Forced Elec PwrSup Fail	The turbine remained off-line to replace a failed 24 VDC power supply in the turbine EHC system.

DATE	TYPE	NARRATIVE
8/27/94	Forced AmplCard Fail Wearout Turb.	Plant at 100% power when operators observed the main turbine trip to manual control mode due to high header pressure, as a result of undesired main steam control valve throttling. Further investigation showed this was caused by an erratic load control signal. The plant output subsequently oscillated on several occasions due to the electrohydraulic control system (EHC) seeing a load limit as a result of the degraded oscillating load signal. The plant subsequently shut down in order to effect repairs to the load control circuit because the nature of the failure caused plant output oscillations in both automatic and manual turbine control modes. EHC system degraded in that it could no longer provide stable load control. Found that the load reference amplifier card a72 had a low and oscillating output, thus causing the load control circuit to control at improper levels. Root cause was the failure of a zener diode on the card, due to age related degradation. Replaced the load reference amplifier card, a piece part of the EHC control supercomponent, in-kind, after performing bench testing and calibration. Plant subsequently returned on line, and load verified to be properly controlled.
8/31/94	Forced Turb. Fail RefCrd	The turbine was taken off-line in order to replace a faulty EHC load reference card.
3/14/95	Forced Elec Relay Fail	The turbine was manually tripped from 7% power due to problems with a power sensing relay in the EHC cabinet that prevented switching the EHC control power from House power to PMG power.
5/26/95	AtSD Relay Fail Turb.	The plant was shut down in a refueling outage. Instrument and controls personnel performing scheduled preventive maintenance testing on the EHC panel (electronic control section) found that one of the functions did not perform as required. One of the 2 out of 3 logic elements that actuates a turbine trip when there is a fault signal on the 125v trip bus was not performing as required by the maintenance procedure. With the plant shutdown there was no immediate effect on plant operability but the electronic portion of the EHC system was considered degraded. Troubleshooting by instrument and controls personnel indicated the cause of the problem was a faulty relay (k19*4) located on circuit board 1tm2-a004. (this would be a piece part) the exact cause for the failure is not known but the technicians think there was likely contact degradation due to normal aging and cyclic fatigue. The failed piece part was replaced with an “in kind” spare. After installation, the original maintenance testing was repeated with satisfactory results. The EHC system (electronic controls portion) was then declared operable and returned to service.
6/2/95	None Solenoid Sticking Wearout Turb.	Plant at 100% power. During monthly test of the “ b “ master trip solenoid valve in the electrohydraulic control system, it was found to bind and sporadically not operate. Train degraded because it could no longer be relied upon to trip the turbine on demand. No effect on plant due to train redundancy. Root cause appears to be wear associated with age related degradation. Replaced entire solenoid assembly, a piece part of the electrohydraulic control system, and tested it satisfactorily.

DATE	TYPE	NARRATIVE
6/4/95	AtSD Relay Fail Turb.	The unit was shut down in a refueling outage. The outage was in its last stages with preliminary planning for plant heatup in progress. Personnel monitoring the status of equipment needed for turbine chest/shell warming noted that there was a "speed signal backup overspeed trip" alarm present on main board 5. With this alarm present the turbine would trip when trying to warm chest/shell or roll the turbine and it was therefore considered inoperable but with the plant still technically in refuel, the failure had no immediate effect on plant operability. Troubleshooting by instrument and controls personnel revealed that the cause of the problem was a faulty relay (k1*2) on circuit card 1pc2-a002 (a piece part) that was not changing state when required by the EHC electronic circuit. The exact cause of the failure is unknown but the technicians think there was likely a contact degradation condition associated with the relay. The relay was replaced with an "in kind" spare obtained from warehouse spares. After installation, the alarm immediately cleared, and the associated EHC circuits were verified to operate properly according to applicable plant procedures.
6/18/95	SwitchGear Forced Design Xfmr	LER 443-95002-00 On June 18, 1995 at 1827 a manual reactor trip was initiated from 100% power. The reactor {ab} was manually tripped after power was lost to both turbine electrohydraulic control (EHC) {tg} pumps. This event was reported to the NRC pursuant to 10 CFR 50. 72 (b) (2) (ii), actuation of the reactor protection system (RPS) and engineered safety feature (ESF) system. There were no adverse safety consequences as a result of this event. Prior to the reactor trip, unit substation us-14 {ea} was cross-tied to unit substation us-21 to restore power to two motor control centers, after the primary feeder breaker on us-21 tripped open due to a ground caused by a failed surge arrester. The us-14 transformer tripped, while cross-tied to us-21, due to an unrelated end-of-life fault (primary to secondary) on the us-14 13. 8 kv non-safety related transformer. This resulted in the loss of power to the EHC pumps. The loss of power to buses us-14 and us-21 complicated the secondary plant trip response. The root cause of this event was determined to be an inadequate design for the 13. 8 kv non-safety related transformer; have taken actions to correct the transformer and surge arrester conditions. These include replacing trip critical 13. 8 kv non-safety related transformers, developing further guidance regarding cross-tying electrical buses and replacing surge arresters.
9/20/95	LoadRed Turb.	Load reduction to 75% to repair turbine control irregularities, also on 9/22/95.
1/16/96	None Turb. POT Wearout Fail	The plant was operating at full power. Operations personnel reported that when they were adjusting turbine load by manipulating the turbine load limit potentiometer associated with the electrohydraulic controls (EHC) on the main control board, several of the indicator lights unexpectedly flickered that, under normal conditions, indicate that EHC control is shifting to the "load set control" operating mode. The observed response indicated the presence of a potential malfunction in the electronics portion of the electrohydraulic controls and the EHC system operability was therefore considered degraded. There was no immediate effect on plant operability. Troubleshooting by instrument and controls personnel revealed that the cause of the problem was a faulty potentiometer (a piece part) in the main control board section of the electrohydraulic control system. The cause of the failure was attributed to the degradation of the electrical connection between slide & wiper within the potentiometer as the result of normal wear. The faulty potentiometer in the electrohydraulic control unit was replaced with an "in kind" spare obtained from warehouse spares. After installation, the equipment control features were verified to function properly per applicable plant procedures and declared operable.

DATE	TYPE	NARRATIVE
1/27/96	Forced Turb. LVGCard Fail	The control room received an automatic reactor trip from 100% power. The reactor trip was due to high pressurizer pressure resulting from a main turbine load rejection event. The load rejection was caused by the turbine Combined Intercept Valves and the Turbine Control Valves closing. The valves had closed due to a faulty position mismatch signal generated by a malfunction in the electrohydraulic control (EHC) cabinet (1tsicp26). 1tsicp26 provides speed control of the main turbine. The closure of the turbine control and Combined Intercept Valves was initiated by the failure of one of the two “low value gate” circuit cards in the turbine speed control circuit of the EHC system. This resulted in a large speed error signal and a valve close signal. It is not known which of the two low value gate cards had failed or why. The failure is believed to be due to degradation of electronic components on one of the cards. The two low value gate cards, 1s1-b401 and 1s1-b501, were replaced with like kind and tested satisfactory. These cards are considered as piece parts of 1TSICP26.
3/07/96	None Solenoid Sticking Turb.	Plant at 100% power. During scheduled testing of the mechanical trip solenoid valve, a part of the electrohydraulic control system (EHC), it was found to have an excessive delay time due to sluggish operation. System degraded because this turbine trip feature is required to be operable when the plant is operating. No effect on the plant as other required turbine trip features were available. Disassembly of the solenoid valve showed sludge deposits on the solenoid slug, causing sluggish operation. This solenoid was just installed during the 11r outage during digital turbine control system upgrade. Root cause or source of the sludge is unknown at this time. Cleaned solenoid slug and bore. Subsequent testing resulted in satisfactory operating times.
6/10/96	Forced	Manually tripped the main turbine due to EHC problems, reduced reactor power to 15%; also on 6/25/96.

APPENDIX E
SURVEY RESPONSE COLLATION

Note: Bold italic entries in the tables indicate that there are associated notes in the comment section of this appendix.

1Q	Replaced load set / load reference motor-driven pots with electronic devices.	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	Y	P	N	N	N
1P	Added valve sequential reset after fast closure initiation (Mk I).	N	N	NA	N	NA	N	N	N	NA	Y	N	N	NA	N	N	NA	N	NA	Y	N	NA	NA
1O	Throttle pressure limiter removal (Mk II).	N	N	N	N	Y	N	N	N	N	N	N	N	N	NA	N	N	N	N	NA	Y	Y	Y
1N	Added speed error filter.	N	N	Y	N	Y	N	N	N	Y	N	N	N	N	N	N	N	N	N	N	Y	Y	Y
1M	Added trip sensor status supervision (Mk II).	NA	NA	N	NA	N	NA	NA	NA	N	NA	NA	NA	N	NA	NA	N	NA	N	NA	NA	N	N
1L	Added second contact to KT106 relay contacts (Mk I).	N	Y	NA	Y	NA	Y	N	P	NA	N	Y	N	NA	Y	Y	NA	N	NA	Y	N	NA	NA
1K	Redundant press. sensors (PWR, Mk I & II).	Y	N	N	NA	N	N	NA	P	Y	NA	NA	NA	N	Y	NA	NA	NA	NA	NA	Y	N	N
1J	Change to rate sensitive PLU (Mk I).	N	N	NA	Y	NA	N	Y	Y	NA	Y	N	N	NA	N	N	NA	Y	NA	Y	N	NA	NA
1I	Replaced of TBWD sensors with noncontacting type.	N	N	N	N	N	N	N	N	P	N	Y	N	N	N	N	N	N	N	N	N	Y	N
1H	TBWD logic mod. to avoid trips during test or added TBWD wrap around logic.	N	N	N	N	N	N	N	N	N	N	Y	N	N	Y	N	Y	Y	Y	Y	N	Y	N
1G	Changing turbine shaft vibration probes to noncontacting type.	N	N	N	N	N	N	N	N	Y	N	Y	N	N	N	***M***	N	N	N	N	N	Y	Y
1F	Added intercept valve fast close delay to avoid spurious actuation from noise (Mk I).	N	N	NA	Y	NA	N	N	N	NA	N	N	Y	NA	N	N	NA	Y	NA	P	Y	NA	NA
1E	Added SLRCs (BWR only).	NA	NA	NA	Y	NA	NA	N	NA	NA	Y	Y	Y	NA	NA	Y	N	Y	Y	***N***	NA	NA	NA
1D	Replaced of back up overspeed test auto switch with a manual switch (Mk I).	N	N	NA	N	NA	N	N	Y	NA	N	N	Y	NA	N	N	NA	N	NA	P	N	NA	NA
1C	Replaced PLU test automatic switch with a manual switch (Mk I).	N	N	NA	N	Y	N	N	Y	NA	N	N	Y	NA	N	N	NA	N	NA	P	N	NA	NA
1B	Revised stop valve logic to avoid spurious valve closing for MSV-2 testing (Mk I).	N	Y	NA	N	NA	Y	Y	P	NA	Y	Y	N	NA	N	N	NA	Y	NA	P	N	NA	NA
1A	Replaced pressure transducer with Rosemounts.	Y	N	N	Y	Y	Y	N	Y	Y	Y	N	P	N	Y	Y	Y	P	Y	Y	Y	N	N
	Number of Units at the Site	1	2	4	2	1	1	2	1	1	2	2	2	2	3	2	1	2	1	2	1	2	1
	Reactor Type	P	P	HW	B	P	P	B	P	P	B	B	B	P	P	B	B	B	B	B	P	P	P
	Model (Mk I or Mk II)	Mk I	Mk I	Mk II	Mk I	Mk II	Mk I	Mk I	Mk I	Mk II	Mk I	Mk I	Mk I	Mk II	Mk I	Mk I	Mk II	Mk I	Mk II	Mk I	Mk I	Mk II	Mk II
	Plant	ANO 2	Browns Ferry	Bruce	Brunswick	Callaway	Calvert Cliffs	Dresden	Ft. Calhoun	Gentilly	Hatch	LaSalle	Limerick	Maanshan	Oconee	Peach Bottom	Perry	Quad Cities	River Bend	SSES	Summer	Vogtle	Wolf Creek

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	Plant	ANO 2	Browns Ferry	Bruce	Brunswick	Callaway	Calvert Cliffs	Dresden	Ft. Calhoun	Gentilly	Hatch	LaSalle	Limerick	Maanshan	Oconee	Peach Bottom	Perry	Quad Cities	River Bend	SSES	Summer	Vogtle	Wolf Creek
4	What portion of the EHC generally causes the most problems?	Elec	Elec	Hyd	Hyd	***Hyd***	Hyd+Elec	***Hyd***	Elec	***Elec***	Hyd	Hyd+Elec	***Hyd***	Vlvs	Hyd	Hyd	Hyd	***Hyd+Elec***	Elec	***Elec+Vlvs***	***Hyd+Elec***	Elec+Vlvs	***Hyd***
3B	If it is category A1, describe the impact.	NA	NA	NA	***MPFF***	NA	NA	NR	NA	NA	NR	NR	NR	NA	NA	NA	***Monitor***	***Min***	NA	NA	NA	NA	NA
3A	If it is category A1, it is due to hydraulics, electronics, both, or other?	NA	NA	NA	***Hyd***	NA	NA	Both	NA	NA	Hyd	Both	Hyd	NA	NA	NA	***Both***	***Both***	NA	NA	NA	NA	NA
3	What is the maintenance rule category for your EHC system?	A2	A2	NA	A1	A2	A2	A1	A2	NA	A1	A1	A1/A2	NA	A2	A2	A1	A1	A2	A2	A2	A2	A2
2	If your plant power level has been uprated, provide the amount of increase.	0	0	10	5	0	0	0	5	0	6	0	5.7	1	0	5.7	0	0	0	5	4.5	5	0
1oth	List any other modifications.	NR	NR	***TPL***	NR	***Y/L***	***Y/L***	***Y/L***	NR	NR	NR	NR	***Y/L***	NR	NR	NR	***Y/L***	***Y/L***	***Y/L***	NR	***Y/L***	***Y/L***	NR
1AE	Added a delay to selected turbine trips or removed the trip. If so, please list.	N	N	***Y***	N	***Y/L***	N	***Y/L***	P	N	Y	***Y/L***	N	N	***Y/L***	N	N	***Y/L***	***Y/L***	***Y/L***	N	Y	***Y/L***
1AD	Use 2/3 logic for most turbine trip sensors (Mk I). If so, please list which sensors.	N	Y	NA	N	Y	***Y/L***	N	***P/L***	NA	Y	***Y/L***	Y	NA	***Y/L***	Y	NA	N	NA	***Y/L***	***Y/L***	NA	***Y/L***
1AC	Added restricting orifice to FASV-P port.	N	Y	N	Y	N	N	Y	Y	N	Y	N	N	N	Y	Y	Y	Y	Y	Y	N	Y	N
1AB	Replaced air gap solenoid valves with wet armature type.	N	N	N	N	N	Y	N	N	N	N	N	N	N	Y	N	N	Y	N	N	N	Y	N
1AA	Hydraulic piping improvements per TIL-841 and/or TIL-1089.	N	N	N	N	Y	Y	N	Y	N	Y	N	N	N	N	Y	N	S	Y	Y	Y	Y	Y
1Z	Disk dump valve clearance increase.	N	N	N	N	N	Y	N	N	N	Y	N	N	N	N	Y	N	N	N	N	N	Y	N
1Y	Added control valve accumulators.	N	N	N	Y	N	N	Y	N	N	Y	Y	Y	N	N	N	P	Y	Y	N	N	N	N
1X	Replaced single coil electrical trip solenoid valve (Mk II).	NA	NA	N	NA	Y	NA	NA	NA	Y	NA	NA	NA	Y	NA	NA	Y	NA	Y	NA	NA	Y	Y
1W	Modified master trip solenoid valve logic for improved reliability.	N	N	N	N	N	N	N	P	N	N	N	N	N	N	Y	N	N	N	N	N	N	N
1V	Decrease control valve test reopening rate.	N	N	N	N	N	N	N	N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
1U	Replaced meter relays in the monitor panel (Mk I).	N	N	NA	N	NA	Y	N	N	NA	Y	N	N	NA	N	Y	Y	N	NA	N	N	NA	NA
1T	Replaced/modification of DC power supplies.	N	N	N	N	N	Y	N	N	N	N	N	N	N	N	N	N	Y	Y	N	N	N	N
1S	Replaced valve limit switches.	N	N	N	Y	N	Y	N	P	N	N	N	N	N	Y	Y	N	Y	N	Y	N	N	N
1R	Replaced mercury-wetted relays.	N	N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	Y	N	N

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	Plant	ANO 2	Browns Ferry	Bruce	Brunswick	Callaway	Calvert Cliffs	Dresden	Ft. Calhoun	Gentilly	Hatch	LaSalle	Limerick	Maanshan	Oconee	Peach Bottom	Perry	Quad Cities	River Bend	SSES	Summer	Vogtle	Wolf Creek
15B	If yes, do you use the data for predictive maintenance purposes (e.g., trending)?	N	NA	N	NA	***N***	N	***Y/L***	Trend	N	N	N	***N***	***Y/L***	Y	2xfail	***N***	***N***	N	PwrSup	N	N	Hyd
15A	Do you have a maint. history database or other maint. history records?	Y	N	Y	N	Y	Y	Y	***Y***	Y	Y	Y	N	Y	Y	***Y***	Y	Y	Y	***Y***	Y	Y	***Y***
14B	If so, how is data used?	NA	NR	NA	NA	NR	NA	NA	NA	Trend	NR	NA	Diag	NA	NA	NA	***Cmt***	NR	NA	GenHlth	TS	TS	NA
14A	If so, what data is collected?	NA	NR	NA	NA	NR	NA	List	NA	NR	NR	NA	PlntDA	NA	NA	NA	PlntDA	Specfic	NA	List	Specfic	TempMnt	NA
14	Do you collect on-line data prior to outages to assist in maintenance planning?	N	Y	N	N	Smetim	N	***N***	N	***Y***	Smetim	N	Y	N	N	N	***Y***	***Smetim***	N	***Y***	***Smetim***	***Y/L***	N
13B	If so, who performs (site / GE / corp / other)?	Site	Site	NA	***GE/3rd***	***GE/Site***	3rdPty	***Corp***	All	***GE/Site***	GE / Site	***GE/Site***	Corp	Site	***All***	Site	***Site***	***Corp***	***All***	***GE/3rd***	***Site***	***Site***	Site
13A	Do you perform a root cause analysis for EHC electronics failures?	Smetim	Smetim	***Never***	Smetim	Smetim	Smetim	Smetim	Smetim	Alwys	Smetim	Alwys	Smetim	Smetim	Alwys	Smetim	Smetim	Smetim	Smetim	Smetim	Alwys	Smetim	Smetim
12	Describe process for determining when to replace a component during routine maint. Include symptoms used.	NR	ResDbt	***ResDbt***	***RepFail***	***ResDbt***	***OOS***	***ResDbt***	***ResDbt***	***OOS***	NR	***Hidbt***	ResDbt	NR	***Cmt***	***ResDbt***	***ResDbt***	***ResDbt***	***Cmt***	***ResDbt***	NR	***ResDbt***	***ResDbt***
11C	Is any periodic replacement / refurb.? If so, which devices?	N	***Y***	N	Y	N	***Cmt***	***Y/L***	N	N	Y	NA	NR	***Y/L***	N	NA	Y	***Y/L***	***Cmt***	N	N	***PwrSup***	N
11B	Indicate where repairs are done (e.g., on-site, vendor, third party), if applicable.	NA	NA	Site	***GE***	Site	NA	NA	NR	Site / GE	NR	***Corp***	NA	NA	***Site/GE***	NA	***NA***	Site / GE	NA	GE / 3rd	Site	NA	Site / GE
11A	What parts replacement philosophy do you use (repair / discard)?	Dscrd	Dscrd	Repr	Repr	***Repr***	Dscrd	Dscrd	***Cost***	***Dsc/rep***	NR	Dscrd	Dscrd	Dscrd	Dscrd	Dscrd	Dscrd	***Repr***	Dscrd	***Repr***	Repr	Dscrd	***Repr***
10	Do you bench test replacement parts before installing them in the plant?	Y	***Y/All***	***N***	***Boper***	***Y/L***	N	***Y/L***	***Y***	***N***	NR	***DCopr***	Y	***Y/L***	N	***Y***	***Cmpl***	***Y/L***	N	***Cmpl***	***DCopr***	***Y/L***	***Boper***
9	What maintenance procedure philosophy do you use?	SA	SA	SA	Vref	***Vref***	SA	***SA***	SA	Vref	Vref	SA	SA	Vref	SA	SA	SA	SA	SA	***Vref***	SA	***Vref***	Both
8	What maintenance procedure process do you use?	Few	***Few***	Many	***Many***	***Special***	Few	Few	Many	***GEFLU***	Few	Many	Few	Few	Few	***Both***	Few	***Few***	Few	***Many***	***Few***	***Many***	Few
7	Do you perform any on-line maintenance?	***CM***	***Y***	***CM***	N	***Y/L***	***C/PM***	***Y/L***	***Y***	N	N	N	Y	N	N	***NM***	***CM***	***N***	N	***Y/L***	N	***CM***	***NM***
6	How frequently do you perform maint. / cal. on the EHC (# cycles)?	1	1	***2 Yrs***	1	***1/L***	1	M	1	***1***	1	1	***1***	1	1	1	***1***	***1***	3	***3/L***	***3/L***	3	1
5	What approach to EHC electronics maintenance is used at your plant?	Sel	Many	Sel	Sel	***Lst***	Sel	Sel / GE	Sel	***Sel***	***Sel/GE***	Many	Sel	Sel	Sel	Sel	***Sel***	***Sel***	Sel	Sel	Sel	Sel	Sel

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	16A	16B	16C	16D	16E	16F	16G	16H	16I	16J	16K	16L	16M	16N	16O
Plant	Mechanical overspeed trip device test freq.	Mechanical trip valve test freq.	Mechanical trip piston test freq.	Pressure regulator failover testing freq. (BWR only).	Pressure regulator tuning freq. (BWR only).	Electrical trip valve test freq.	Power/load unbalance test freq.	Backup overspeed trip test freq.	Thrust bearing wear detector test freq.	Backup speed amplifier test freq.	Turbine control valve tests freq.	Turbine stop valve tests freq.	CIV tests freq.	Bypass valve tests freq. (BWR only).	Other EHC test freq.
ANO 2	Fcycle	None	None	NA	NA	None	None	Fcycle	None	None	Monthly	Monthly	Monthly	NA	NR
Browns Ferry	Monthly	Monthly	None	Special	Fcycle	Weekly	Weekly	Fcycle	Weekly	Monthly	Monthly	Qtr	Qtr	Qtr	NR
Bruce	Weekly	Weekly	Weekly	NA	NA	Weekly	Weekly	Weekly	Weekly	Weekly	Monthly	Weekly	Weekly	NA	NR
Brunswick	None	Weekly	None	None	None	Weekly	Weekly	Weekly	Weekly	Weekly	Qtr	Qtr	Qtr	Weekly	NR
Callaway	Qtr	Qtr	Qtr	NA	NA	Qtr	Qtr	Qtr	Startup	None	***Qtr***	***Monthly***	Weekly	NA	NR
Calvert Cliffs	Weekly	None	None	NA	NA	None	Qtr	Weekly	Qtr	Startup	Qtr	Qtr	Qtr	NA	***MTSVWK***
Dresden	Startup	Weekly	Weekly	Special	Fcycle	Weekly	None	Startup	Weekly	None	Monthly	Weekly	Weekly	None	NR
Ft. Calhoun	Fcycle	Fcycle	Fcycle	NA	NA	Fcycle	Weekly	Weekly	Weekly	None	Qtr	Monthly	Monthly	NA	NR
Gentilly	Weekly	None	Weekly	NA	NA	Weekly	Weekly	Weekly	Weekly	Monthly	Monthly	Weekly	Weekly	NA	NR
Hatch	Fcycle	Fcycle	Fcycle	5-9 yrs	5-9 yrs	Weekly	Weekly	Weekly	Monthly	Monthly	Monthly	Monthly	Monthly	Qtr	NR
LaSalle	Startup	Weekly	Weekly	Special	Fcycle	Weekly	None	Startup	Weekly	None	Monthly	Weekly	***LL***	None	NR
Limerick	Fcycle	Monthly	None	Special	Fcycle	Weekly	Weekly	Fcycle	Weekly	Weekly	Monthly	Qtr	Qtr	Monthly	***AcumMth***
Maanshan	Weekly	Weekly	Weekly	NA	NA	Weekly	None	Weekly	Weekly	Weekly	Weekly	Weekly	Weekly	NA	NR
Oconee	Startup	18 Mnt	None	NA	NA	Weekly	18 Mnt	Startup	Weekly	Weekly	Qtr	Qtr	Qtr	NA	NR
Peach Bottom	Fcycle	Weekly	None	Special	Special	Weekly	Weekly	Fcycle	Weekly	Weekly	Qtr	Weekly	Weekly	Monthly	NR
Perry	Weekly	Weekly	Weekly	Outage	Fcycle	Weekly	Weekly	Weekly	Weekly	Monthly	Qtr	Monthly	Monthly	Monthly	NR
Quad Cities	***Weekly***	Weekly	None	Special	Fcycle	None	Weekly	2 Yrs	Weekly	Weekly	Monthly	Weekly	Weekly	Monthly	***MTSVwk***
River Bend	Monthly	Monthly	Monthly	None	Fcycle	Monthly	Weekly	Weekly	Monthly	Weekly	Qtr	Qtr	Qtr	Monthly	NR
SSES	Weekly	None	None	Special	6 yrs	Weekly	Weekly	Weekly	Monthly	Weekly	Qtr	Qtr	Qtr	Weekly	NR
Summer	***Weekly***	Weekly	None	NA	NA	Weekly	18 Mnt	18 Mnt	None	None	Qtr	Qtr	Qtr	NA	NR
Vogtle	Monthly	Monthly	Monthly	NA	NA	Monthly	Monthly	Monthly	***NA***	Monthly	Qtr	Monthly	Monthly	NA	NR
Wolf Creek	Startup	Fcycle	Startup	NA	NA	Startup	Startup	Startup	Startup	Startup	Qtr	Qtr	Qtr	NA	NR

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25	Have you had abnormal responses to oper. actions?	N	***Y/L***	N	N	***N***	N	N	N	N	N	N	N	NR	N	***Y/L***	***Y/L***	N	N	***Y/L***	N	N	***Y/L***
24E	Describe any sensitivities.	NR	NR	NR	***Cmt***	NR	NR	NR	NR	NR	NR	NR	***Cmt***	NR	NR	***Y***	NR	***Cmt***	NR	NR	NR	NR	NR
24D	Are the elec. too sensitive to noise?	N	N	N	N	***N***	N	Y	N	N	N	N	***Y/L***	N	Y	***Y/L***	N	N	N	N	N	N	***Y/L***
24C	Are the elec. too sensitive to vibration?	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
24B	Are the elec. too sensitive to humidity?	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
24A	Are the elec. too sensitive to temp?	N	***Y/L***	N	N	N	Y	Y	Y	N	N	Y	N	N	Y	***Y***	N	N	N	Y	***Y/L***	N	Y
23	Describe any problems with the EHC operation and testing.	NR	***Y/L***	None	None	***VPmtr***	NR	***Y/L***	***MDPOTS***	NR	NR	NR	***Y/L***	NR	NR	***Y/L***	None	None	***Y/L***	***Y/L***	***Cmt***	NR	NR
22	Describe any major problems with the EHC operation and test procedures.	NR	NR	NR	None	***None***	NR	***Y/L***	NR	***Y/L***	NR	NR	None	NR	***Y***	None	None	***None***	***GEFLU***	***GEFLU***	***GEFLU***	NR	NR
21D	Do oper. use the max. combined flow limiter (BWR)?	NA	N	NA	N	NA	NA	Y	NA	NA	N	N	N	NA	NA	N	N	***N***	N	N	NA	NA	NA
21C	Do the oper. ever use stage press. feedback (PWR)?	N	NA	N	NA	N	N	NA	N	***Y/Test***	NA	NA	NA	***Y/Test***	***Y/Test***	NA	NA	NA	NA	NA	N	N	***Y/Test***
21B	Do the operators ever use the load limiter?	Y	N	N	NA	***Y***	N	NA	***Alwys***	***Alwys***	NA	NA	NA	***Y/Pwr***	N	NA	NA	NA	NA	***Y/L***	***100% Pwr***	***Alwys***	***Y***
21A	Do oper. use the throttle press. limiter (PWR)?	N	NA	N	NA	N	N	NA	N	***Y/L***	NA	NA	NA	***Y/Pwr***	N	NA	NA	NA	NA	NA	N	N	N
20	Do the operators ever use the standby turbine control?	N	NA	***Rare***	NA	***N***	NA	NA	NA	N	NA	NA	NA	N	N	NA	NA	NA	NA	NA	NR	***Y/Maint***	***Y/Maint***
19E	Does the EHC challenge the plant operators at other times? Please specify.	NR	N	NR	NR	NR	NR	NA	NR	NR	NR	NR	NA	NR	NR	NR	NR	N	NR	NR	NR	NR	NR
19D	Does EHC challenge oper. during power changes?	N	N	N	N	N	N	N	N	N	N	N	N	Y	N	N	N	N	N	***Y/L***	N	N	N
19C	Does EHC challenge oper. during shutdown?	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	Y	N	N	N	***Y/L***	N	N
19B	Does EHC challenge oper. during startup?	N	N	N	N	N	N	N	***Y/L***	N	N	***Y/L***	***Y***	N	N	N	***Y***	N	N	***Y/L***	N	N	N
19A	Does EHC challenge oper. during on-line testing?	***Y/L***	N	N	N	N	***Y/L***	N	N	N	N	***Y/L***	***Y/L***	***Y/L***	N	N	N	***Y/L***	N	***Y/L***	***Y/L***	N	N
18	Has the EHC electronics contributed to plant down time or plant power reductions?	***Min***	Y	***Y/L***	***Y/L***	***N***	***Y/L***	***Y***	Y	N	N	***Y/L***	***Y***	N	***Y/L***	***Y***	***Y***	***Y***	***Y/L***	***Y/L***	***Y/L***	***Y/L***	***Y/L***
17B	Has the elec. caused an ESF actuation?	N	N	N	N	N	N	N	N	N	N	N	Y	N	NR	N	N	N	N	N	***Y/L***	N	N
17A	Has the elec. caused a plant trip?	None	Y	***2***	***1***	***5/L***	***2/L***	Y	***1/L***	***2/L***	***None***	Y	Y	***3***	***Y/L***	***None***	None	***Y/L***	***Y/L***	***2/L***	***Y/L***	***1/L***	***5/L***

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30F	Any other problems with current maint. procedures?	NR	NR	NR	NR	NR	NR	***Cmt***	***Cmt***	NR	NR	NR	NR	NR	NR	NR	NR	***Y/L***	NR	***Cmt***	***Cmt***	NR	NR
30E	Is system documentation inadequate?	N	N	N	***GEDOC***	Y	N	Y	N	***Y/L***	N	Y	N	N	Y	Y	N	N	***Y***	***Y***	Y	GEDOC	N
30D	Current maint. proc. / docs unclear or incorrect?	N	Y	N	N	N	N	Y	N	N	N	Y	N	N	Y	N	N	Y	N	Y	Y	***Y***	N
30C	Are maint. proc. / docs too complex?	N	N	N	N	N	N	Y	N	Y	N	Y	N	N	N	N	N	N	N	N	N	N	N
30B	Data recording in maint. proc. inadequate?	N	N	N	N	N	N	N	N	Y	Y	Y	N	N	N	N	N	Y	N	N	N	Y	N
30A	Current maint. proc. / docs insufficiently flexible?	N	N	N	N	N	N	Y	N	N	N	Y	N	N	Y	N	N	N	N	N	N	N	N
29	Any replacement modules DOA / failed within 2 weeks?	N	N	N	N	N	***Y/SADI***	N	Y	N	N	Y	***Y***	N	N	Y	NR	***Y/L***	***Y/L***	N	N	N	N
28	Are there any indications that aging is causing a higher failure rate?	N	N	N	N	N	***Y/SADI***	***Y/L***	***Y/L***	N	N	***Y/L***	N	***Y/L***	N	N	NR	***Y/L***	N	***Y/L***	N	***Y/Rly***	N
27B	If known, reason items are high maintenance.	NA	NA	Align	NA	Fail	NA	Fail	NR	NA	NA	Aging	NA	NA	Drift	NA	Drift	Drift	Fail	NR	NR	NR	NR
27A	Indicate which EHC elect. components are high maint.	NR	***Y/L***	Fctrl	NR	***Y/L***	NR	***Y/L***	***Y/L***	***None***	NR	***Y/L***	Servo	NR	***Y/L***	NR	***Y/L***	***Y/L***	***Y/L***	***Y/L***	NR	***T&Mrly***	NR
26H	Are there any other features that make maint. difficult?	NR	***Cmt***	NR	NR	***Cmt***	NR	NR	***Y/L***	***Cmt***	NR	NR	NR	NR	NR	***Cmt***	NR	***Y/L***	NR	***Y/L***	NR	NR	NR
26G	Is replacement of some modules particularly difficult?	N	N	N	N	N	N	N	N	N	N	Y	N	***Y/Servo***	Y	N	N	N	N	***Y/L***	N	Y	N
26F	Are there inadequate test points on some modules? Which ones?	N	N	N	N	N	N	N	N	N	N	N	Y	N	N	N	N	***Y***	N	***Y/BPV Amp***	N	N	N
26E	RO / tech co-ordin. hard for some tasks? Why?	N	N	N	N	N	N	N	N	N	N	N	***Y***	N	N	N	N	***Y***	N	***Y/L***	N	N	N
26D	Does poor access to some components complicate maint?	N	N	N	N	Y / Rly	N	N	N	N	N	N	***Y***	N	N	***Y***	N	N	N	Y / Rly	Y	N	N
26C	Hard to estb. plant cond. for some maintenance tasks?	N	N	N	N	N	N	N	N	Y	N	Y	N	N	N	N	N	Y	N	Y	N	Y	N
26B	Are some cal. meas. hard to make?	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	Y	N	N
26A	Are some cal. adjustments particularly difficult?	Y	***Y/L***	***Y***	N	N	N	N	N	Y	N	Y	Y / DFG	N	Y	***Y***	N	N	Y	Y	***Y/Acel Amp***	Y	N

Note: Bold italic entries in the tables indicate that there are associated notes in the comment section of this appendix.

	Plant	ANO 2	Browns Ferry	Bruce	Brunswick	Callaway	Calvert Cliffs	Dresden	Ft. Calhoun	Gentilly	Hatch	LaSalle	Limerick	Maanshan	Oconee	Peach Bottom	Perry	Quad Cities	River Bend	SSES	Summer	Vogtle	Wolf Creek
31	What is the extent of maintenance training (e.g., training using only system doc., training on a simulator, etc.)?	***Good***	Class/Appr	***Class/Appr***	NR	***Good***	***2 Yrs***	***Class***	***Class/Appr***	***Appr***	NR	***Doc***	Good	NR	***2 Yrs***	***Good***	***Class***	***5 Yrs***	***2 Yrs***	***5 Yrs***	NR	***Good***	***Class/Appr***
32	Is it difficult to keep maint. training current?	N	Y	N	NR	Y	Y	***Y***	Y	Y	N	Y	Y	Y	N	N	Y	Y	Y	Y	NR	Y	Y
33	Describe simple changes to hardware/procedures that would ease maint.	NR	NR	NR	NR	***GEFLU***	NR	***Y/L***	NR	***Y/L***	NR	***Y/Simu***	***Y/L***	NR	NR	NR	***Y/L***	***Y/L***	***Y/L***	***Y/L***	NR	NR	NR
34	Describe an instr. or could, simplify EHC maint.	NR	NR	NR	NR	NR	NR	***Y/L***	NR	***Y/L***	NR	NR	***Y/L***	NR	NR	NR	NR	***Y/Simu***	NR	***Y/L***	NR	NR	NR
35	Have upgrades/corrective actions on the electr. generally worked as intended?	Y	Y	Y	Y	***Y***	Y	Y	Y	***N/L***	Y	Y	Y	Y	Y	Y	Y	***Y***	***N/L***	Y	***Y***	Y	Y
36	Have upgrades/corrective actions on the electr. created additional problems?	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	***Y/L***	Y	N	N
37A	Troubleshooting procedures are not used.	Y	N	N	N	***Y***	***Special***	N	N	***N***	N	Y	***N***	Y	N	N	Y	Y	N	***Y***	N	Y	N
37B	Are current troubleshooting procedures insufficiently flexible?	N	N	N	N	N	N	N	N	N	N	N	N	N	Y	Y	N	N	N	N	N	N	N
37C	Are troubleshooting procedures too complex?	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
37D	Are troubleshooting procedures unclear?	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
37E	Is system documentation inadequate?	N	N	N	Y	N	N	N	N	N	N	Y	N	N	N	N	N	N	N	N	N	N	N
37F	Any other comments on troubleshooting?	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
38	Have you had any cases where identifying a failed module was very difficult?	N	***Y/L***	Y	N	N	N	***Y/L***	***Y/L***	N	NR	***Y/L***	***Y***	N	N	***Y/L***	N	***Y/L***	***Y/L***	***Y/L***	***Y/L***	***Y/Rly***	N
39	Describe simple hardware/procedure changes that would ease troubleshooting.	NR	NR	None	NR	NR	NR	NR	NR	NR	NR	***Y/TPs***	***Y/L***	NR	NR	NR	NR	***Y/L***	***Y/L***	***Y/L***	NR	***RlyLogic***	NR
40	Describe an instrument tool that does, or would, simplify electr. troubleshooting.	NR	***Y/L***	***Y/L***	NR	***Y/L***	NR	NR	NR	NR	NR	NR	None	NR	NR	NR	***Y/L***	***Y/L***	NR	None	NR	NR	NR
41A	Do some replacement parts have long lead times?	Y	N	N	N	N	Y	Y	N	Y	Y	Y	***Y***	N	Y	***Y***	Y	Y	N	Y	N	N	N
41B	Are some replacement parts of poor quality?	N	Y	N	N	N	Y	***Y/Servo***	N	N	N	N	Y/PwrSup	N	N	***Y***	N	N	N	N	N	N	N
41C	Are any spares incompatible with old components?	N	N	N	N	N	N	N	N	Y	N	N	N	N	N	***Y***	N	N	N	N	N	N	N

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	Plant	ANO 2	Browns Ferry	Bruce	Brunswick	Callaway	Calvert Cliffs	Dresden	Ft. Calhoun	Gentilly	Hatch	LaSalle	Limerick	Maanshan	Oconee	Peach Bottom	Perry	Quad Cities	River Bend	SSES	Summer	Vogtle	Wolf Creek
46B	Other statements. (See also list of comments table.)	NA	Gnd Offsets	Good Techs	NA	Many Imprvmts	NR	Problems	Good Maint	Aging Concern	NR	Aging	Cmt	NR	Tight Test Criteria	NR	SB&PR Concerns	Worried	Keep On	Lst	Various	NA	Various
46A	System reliable comment added?	NA	NR	Y	NA	Y	NR	N	Y	Y	NR	Y	NR	NR	Y	NR	Y	Y	Y	NR	NR	NA	Y
46	Please add any general comments you might have.	NR	***Y***	***Y***	NR	***Y***	NR	***Y***	***Y***	***Y***	NR	***Y***	***Y***	NR	***Y***	NR	***Y***	***Y***	***Y***	***Y/L***	***Y***	NR	***Y***
45	If possible, provide an estimate of the total cost of EHC O&M.	NR	***Y/L***	NR	NR	***Y/L***	NR	NR	NR	NR	***Y/L***	NR	***Y/L***	NR	NR	***Y/L***	NR	NR	NR	***Y/L***	NR	NR	NR
44B	Are you usually successful in getting timely and accurate responses to inquiries from alternate vendors?	NR	NR	Poor	***Good***	NR	NR	NR	Good	NR	Good	NR	Good	NR	Good	NR	NR	NR	Excl	Good	Poor	NR	Good
44A	Are you usually successful in getting timely and accurate responses to inquiries from the EHC vendor?	NR	NR	***Poor***	NA	***Erratic***	***Poor***	***Poor***	Good	***Poor***	Good	***Good***	Good	NR	***Poor***	NR	***Fair***	***Erratic***	***Excl***	***Good***	Poor	***Good***	Good
43G	Do you use alternate vendors for other support?	NR	NR	***Cmt***	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	***LNup***	***Y/L***	NR	NR	NR	NR	NR
43F	Do you use alternate vendors for procedure development?	N	N	N	N	N	N	N	Y	N	N	N	N	N	N	N	N	N	N	Y	N	N	N
43E	Do you use alternate vendors for design of modifications to the EHC?	N	N	N	N	N	N	N	N	N	Y	N	N	N	N	N	N	N	Y	N	N	N	N
43D	Do you use alternate vendors as a second source for EHC modules?	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	Y	N	N	N	N	N
43C	Do you use alternate vendors for refurbishment of failed modules?	N	N	N	N	N	N	Y	Y	Y	N	Y	Y	Y	Y	N	N	Y	N	Y	N	N	Y
43B	Do you use alternate vendors for assistance in root cause analysis of EHC failures?	N	N	N	Y	Y / Hyd	Y	N	N	N	N	N	Y	N	Y	Y	N	Y	N	Y	N	N	N
43A	Do you use alternate vendors for assistance in troubleshooting EHC problems?	N	N	N	N	N	N	N	N	N	N	N	Y	N	N	Y	N	N	N	Y	N	N	N
42A	Do you have a shared inventory for EHC?	N	N	N	N	Y	N	Y	Y	N	NR	Y	N	N	N	N	N	Y	N	N	N	N	Y
42	Describe your parts inventory status.	NR	Good	***10***	***Cmpl***	***7***	NR	***Min***	***Good***	***Life***	NR	***Fair***	Fair	NR	***10***	***2***	NR	***Min***	***Min***	***Fair***	NR	***Cmpl***	Good
41E	Please provide additional information on replacement parts problems.	NR	NR	***Cmt***	NR	PwrSup	NR	NR	***Cmt***	NR	NR	NR	NR	NR	***Cmt***	NR	***SB&PR***	***Y/L***	NR	***Y/L***	N	NR	***Cmt***
41D	Are some parts unavailable or may soon become unavailable.	Y	Y	N	N	***Y***	N	N	Y	***Y/L***	N	Y	Y / PwrSup	***Y/L***	Y	N	Y	Y	***Y/L***	Y	N	N	Y

Item	Plant	Comment
1 E	SSES	Evaluation concluded added SLRCs were unnecessary.
1 G	Peach Bottom	Probes installed. Presently using shaft riders for alarm and trip.
1AD	Calvert Cliffs	Low hydraulic pressure; low lube oil pump discharge pressure.
1AD	Fort Calhoun	High vibration planned.
1AD	LaSalle	EHC pump discharge pressure. Low lube oil pressure.
1AD	Oconee	Low hydraulic pressure; low bearing oil pressure; under voltage; vacuum; MSR level.
1AD	SSES	High exhaust hood temperature, low shaft pump discharge pressure, low hydraulic fluid pressure, low bearing oil pressure, moisture separator high level. Also, use 1/3 taken twice trip logic for low vacuum.
1AD	Summer	1) Feed water heater 5 & 6 Hi-Hi level; 2) EHC low hydraulic pressure; 3) MSR Hi-Hi level; 4) Shaft oil pump low discharge pressure.
1AD	Wolf Creek	All except exhaust hood temp.
1AE	Bruce	Vibration trip may be disabled selectively.
1AE	Callaway	Vibration trip removed.
1AE	Dresden	Put 2.5 sec. delay in the high vibration trip logic.
1AE	LaSalle	Two-second delay on bearing vibration.
1AE	Oconee	Low shaft discharge pressure—alarm only. High exhaust hood temperature—alarm only. TBWD trip removal.
1AE	Quad Cities	Installed 3-second time delay upon high vibration for main turbine trip logic.
1AE	River Bend	RBS added a 10-second time delay to the turbine trip signal.
1AE	SSES	TSI high vibration ~3.3 sec time constant.
1AE	Wolf Creek	Six-second delay on vibration trip (2/2 axis) XX.
1oth	Bruce	Throttle pressure limiter modified to prevent rapid hunting of control valves during shell warm.
1oth	Callaway	Planned modification to add lower load rate increase/decrease to aid operations.
1oth	Calvert Cliffs	Vibration. Deleted.
1oth	Dresden	Changed delay settings for K1-D29 to 25 seconds and K2-D20 to 20 seconds to allow for proper sequencing of oil trip test while preventing turbine trip on failure of faulty linkage on test exit.
1oth	Limerick	Modification to permit isolating bypass valve hydraulics. Modification of hydraulic pump compensators and compensator sense line relocation. Accumulator piping modification to facilitate testing. Isolation valves added to hydraulics filters.
1oth	Perry	Mark II plant had meter relays for BOST testing indication. Installed a modification prior to startup to remove the meter relays and installed an LED logic network for indication. Replaced power supply fan sensors by installing fans with magnetic pickup for sensing failures. Installed stainless steel shutoff valve modification (TIL 894-3). SB&PR buffer amplifier card mod. (SIL 587). Removed ALF logic in SB&PR and EHC. Added a capacitor across the electrical malfunction bus to suppress inductive kick when the relays de-energized. This caused the electrical malfunction light to come on after reset with no genuine input. Planned Modifications: Control valve accumulator (TIL 1123-3). Bypass switch for high hood temperature to bypass trip after startup. Vibration trip 3-second delay. Reducing the set point for the SB&PR flow demand dead band card from 17% to 10% error. This will reduce the difference between channels at transfer from 5 psi to 3 psi. This is in response to pressure amplifier problem described in response to 19. Added surge suppression to electronics malfunction reset bus.
1oth	Quad Cities	Installed isolation valves at skid to isolate all hydraulics from bypass valve hydraulics. Installed EHC pump discharge duplex filters to allow for on-line filter replacement. Installed Group 6 shutoff valves. Plan on implementing the following: MTSV voltage increase, PLU/BUOS test switch replacement, installation of flex hoses & individual isolation valves at turbine control valves, increasing turbine trip sensor logic to 2-out-of-2 logic, installation of Rosemount pressure transmitters in place of GE HQ transmitters, removal of auto load following circuitry.

Item	Plant	Comment
1oth	River Bend	Addition of manual block valves at EHC pump discharge lines. Addition of manual block valves at all steam valve FAS/ETS lines. Addition of accumulators per TIL-1123 to support conversion to PA admission. Addition of third resonance SLRC to support conversion to PA admission. Replacement of HP turbine to support conversion to PA admission. Replacement of load set mop with digital load set card.
1oth	Summer	Disabled high vibration trip. There is a placard on the main control board with guidance on when to manually trip the turbine on high vibration. Throttle pressure compensator removed in 1994. Will remove remote auto and line speed matcher next outage.
1oth	Vogtle	Removed throttle pressure limiter and throttle pressure compensation (excess throttle pressure) circuits. This was done for the purpose of general simplification and to eliminate some "noise" issues during warming and startup. Added main control board push buttons for the operator to manually control the mechanical and electrical lockout valves during trip device testing instead of relying on the automated test circuits. This followed an incident when the turbine tripped after the "stop-go normal" button was pressed. Added speed error filter to reduce hydraulic line motion due to electronic noise. Added an additional requirement that an overspeed direction speed error of at least 0.5 VDC be present prior to arming of the IV fast closure circuit. This was done to eliminate the possibility of a trip due to a single failure in an IV position control or driver card and followed an incident in which all of the IVs fast-closed when the controls were taken from standby to normal with no speed error present. A 3-second time delay was added to the low hydraulic pressure turbine trip circuit to eliminate the possibility of a trip due to mechanical agitation of the pressure switches. The magnitude of the control valve test bias signal that can exist prior to control valve stroke testing being prohibited was increased from 1.0 to 1.5 VDC to compensate for the variation between the actual and intended steam flow/valve curve relationship that existed after a power uprate and RCS temperature reduction. A manually initiated, multiple rate, load setback circuit intended to be used in the event of the loss of a main feedwater pump was installed. The characteristics of the runback were matched to the conditions that Westinghouse predicted would provide the highest probability of avoiding a reactor trip due to low steam generator level. The relays that receive the inputs for the "customer trip from 125 volt station batteries" were changed. The old relays, which were energized at 136 volts for most of our outage, tended to experience coil failures. Since our relays are wired in parallel, a failure of one coil made it likely that the voltage applied by the Westinghouse SSPS system during slave relay testing would be adequate to energize the trip relays. The replacement GE HFA relays can tolerate the higher voltage and have adjustable pickup voltage that can be set above the SSPS test output level. The input sensors for the condenser vacuum and hydraulic pressure trips are being replaced with pressure transmitters and electronics in the Fall 1997 refueling outage. The new instrumentation will be more accurate and not experience drift. Since the status can be monitored with the unit in operation, 2-out-of-2 logic will be used.
3A	Brunswick	Hydraulics—fluid quality.
3A	Perry	Both. Due to not calibrating in our early years, replacing the P/L gate created an offset between SB&PR and EHC. The plant was restricted to 45% for several days in 1993. O-ring failure on a CV shutoff valve forced a shutdown in 1995.
3A	Quad Cities	EHC leaks and electronic circuit card failure.
3B	Brunswick	No unavailability or MPFFs, resulting in a loss of the system.
3B	Perry	Increase monitoring.
3B	Quad Cities	No major impact at this time. Impact on system engineer to develop action plan.
4	Callaway	Filter clogging/pressure compensators.
4	Dresden	(Corp.) 90% hydraulic, 10% electronics.
4	Gentilly	Mostly after a modification.
4	Limerick	Numerous leaks—in particular on Unit 2. Problems with O-rings.
4	Quad Cities	EHC fluid leaks at turbine control valves and circuit card failures.
4	SSES	Electronics—relays, sockets, bulbs, power supplies, meter relays. Valves—limit switches, LVDTs, stroke characteristics.
4	Summer	Fifty percent hydraulics; 50% electronics.
4	Wolf Creek	Pump swings, compensator problems.
5	Callaway	Any available technician on-line. GE and in-house technicians during outage calibration.

Item	Plant	Comment
5	Gentilly	Performed strictly by the same technicians.
5	Hatch	With GE oversight.
5	Perry	In 1994, we hired vendors to aid in EHC and SB&PR alignments. Out of this we got experience and proofed procedures.
5	Quad Cities	Same I&C Foreman supervises a different I&C technician each outage.
6	Bruce	Once every 2 years.
6	Callaway	Check all valve curves and main controls (i.e., load, flow, speed, T&M each outage).
6	Gentilly	At every planned outage, which is nearly once a year.
6	Limerick	Complete lineup each refuel outage, except for limit switch adjustments.
6	Perry	Currently scheduled every RFO but only portions deemed necessary by RSE is done. This is based on operational data and as required to correct problems, perform PMs, or as needed because of steam valve maintenance. When enough data is accumulated to support extending frequencies, that will be done.
6	Quad Cities	Perform complete lineup calibration each refuel outage.
6	SSES	Certain portions done each refuel (e.g., DFGs, SADIs, meter relays, A&T, VCs, op amps, TSI vibration channels, valve limit switches, power supplies). Others approx. every 2-3 cycles.
6	Summer	Used to perform cabinet alignment each refuel outage. This is being changed to every third outage, except for tests of all turbine trip circuits every outage.
7	ANO	Various corrective maintenance.
7	Browns Ferry	Fuller's earth filter every 3 months.
7	Bruce	If a repair is required and is feasible to do on-line, such as board and servovalve replacements, then it will be done.
7	Callaway	Troubleshooting, fan replacements.
7	Calvert Cliffs	Correction of deficiency when necessary; recommended preventative maintenance.
7	Dresden	Verification of PMG power supplies input and output voltages after a refuel outage when near 150 MWhrs.
7	Fort Calhoun	We troubleshoot emergent electronic problems on-line.
7	Peach Bottom	Filter changeouts.
7	Perry	Generally only when forced to by failure. SB&PR power supply, SB&PR pressure amplifier card, EHC cabinet fans.
7	Quad Cities	Do not perform any scheduled on-line electronics maintenance unless a problem develops that can be safely repaired with the unit on-line.
7	SSES	Preventive—recorders, pressure set point bias adjustment, power supply voltage measurements. Corrective (emergency only)—bulbs, fans. (Signal monitoring as necessary to investigate problems.)
7	Vogtle	Hydraulic filter changes; accumulator checks; some instrument calibrations. Some corrective maintenance.
7	Wolf Creek	EHC filter changeout, pump replacement, servo replacement.
8	Browns Ferry	Five to 10 procedures.
8	Brunswick	EHC lineup is a single procedure.
8	Callaway	Special instructions dependent on problems. No specific procedures apply.
8	Gentilly	Use GE field lineup.
8	Peach Bottom	Many procedures for hydraulics. Few procedures for electronics.
8	Quad Cities	We have one main EHC lineup instruction document (uncontrolled) that is routed at the beginning of each outage as a work package.
8	SSES	PM work plans used that reference/incorporate applicable GEK section or GE field lineup instructions.
8	Summer	Wrote our own procedures from field lineup instructions.
8	Vogtle	Use the GE supplied field lineup instructions.
9	Callaway	Utilize GE field lineup and in-house expertise.
9	Dresden	(Corp.) Very general, referring to use of GE qualified personnel.

Item	Plant	Comment
9	SSES	Primarily utilize GE field lineup instruction.
9	Vogtle	We only use the field lineup instructions.
10	Browns Ferry	Test all boards in retired Unit 1 cabinets.
10	Bruce	The repaired system is tested with the new part.
10	Brunswick	Basic operation/calibration.
10	Callaway	Some—will bench test power supplies and some cards.
10	Dresden	Power supplies are fully tested prior to installation. (Corp.) Some cards are tested.
10	Fort Calhoun	To whatever level we can—it depends on the component.
10	Gentilly	We do replacements during an outage, so we do functional tests before startup.
10	LaSalle	Basic DC operation. (Corp.) Hydraulic valves (servo, shutoff, solenoid).
10	Maanshan	We calibrate transmitters, test relays, and test servovalves before putting in service.
10	Peach Bottom	Servovalves tested off-site.
10	Perry	All functions whenever possible. We have 2 procedures. One for cabinet alignment, and one for card calibration that includes bench calibrations.
10	Quad Cities	Mercury-wetted relay cards, power supplies, and miscellaneous circuit cards—if circuit card is suspected as being a problem prior to installation.
10	SSES	Full calibration and burn-in period—cards, power supplies. Dynamic—SLRC, DFG cards.
10	Summer	Basic DC operation.
10	Vogtle	Power supplies; transmitters; pressure switches.
10	Wolf Creek	It is primarily just basic operation, including dynamics. This is dependent on the component.
11A	Callaway	Just starting in-house card repair program. Also, repair power supplies on-site.
11A	Fort Calhoun	Our practice has been to repair circuit cards (by a vendor) unless the repair will cost more than 1/2 of a new board. We have recently purchased a set of used cards from a retired system. Repair if lower cost.
11A	Gentilly	We repair failed circuits if the component is easily identified and available on the standard market. Otherwise we ship it to GE for repair while installing a new one.
11A	Quad Cities	Mercury-wetted relay cards are repaired on-site. Most other card repairs are performed by GE.
11A	SSES	On-site and/or vendor/third party—GE, Encore.
11A	Wolf Creek	On-site with some going back to GE for refurbishment.
11B	Brunswick	Some circuit boards have been returned to GE for failure mode analysis/repair.
11B	LaSalle	Failed circuit cards are sent out for repair.
11B	Oconee	Obsolescence is making it more difficult to discard failed parts. Sometimes it is necessary to do repairs at the board level. We do obvious repairs and send the rest to vendors. The majority go to GE.
11B	Perry	Replace capacitors. Rework cards if forced to by parts availability, but generally don't repair.
11C	Browns Ferry	Master trip solenoid is replaced every 5 years.
11C	Calvert Cliffs	Working on planned replacement of cards program.
11C	Dresden	All power supplies will be refurbished during the next refuel outage. (Corp.) Need a good electronic PM program based on failure history and aging degradation.
11C	Maanshan	1) Power supply electrolytic capacitors; 2) Thrust relays K-12 and K-15; 3) EHC servo filter; 4) EHC ETSV; 5) Turbine pressure transmitter; 6) Power supply fans.
11C	Quad Cities	DC power supplies are sent to a vendor for rebuild every six years. No circuit cards are replaced on PM basis as of yet. Currently evaluating how to proceed on this issue. We have replaced SADI cards, F/V cards, mercury-wetted relay cards, and 3 kHz oscillator cards in the past as a PM activity to try and preclude a failure.

Item	Plant	Comment
11C	River Bend	RBS used to perform periodic replacement of components, but we are moving toward RCM methodology. RCM generally tests components and only replaces/reworks if necessary due to problems with the components. RBS will start performing very detailed testing of EHC power supplies next RF outage. This testing will probably be performed every third RF outage, with ripple testing in the other two outages.
11C	Vogtle	Power supplies.
12	Bruce	Marginal components are replaced at the first opportunity.
12	Brunswick	Repetitive failures.
12	Callaway	We really don't see marginal components. If it doesn't work per design, we replace.
12	Calvert Cliffs	Replace components that do not meet specs.
12	Dresden	Power supplies are refurbished when excessive ripple is observed, or if they cannot pull full load amps. F/V cards were replaced after 2 of 4 cards were noisy, causing false speed signals while on turning gear. (Corp.) Calibration difficulties/failures.
12	Fort Calhoun	If a card/component cannot be adjusted into tolerance during calibration; if unusual behavior is observed, it will be replaced or repaired.
12	Gentilly	If component is out of manufacture's specification, we replace it. Since we have only one turbine, if the behavior is different then expected, we replace the suspected part. We want to be sure of no downtime between outages.
12	LaSalle	Components replaced only if calibration is very difficult to obtain.
12	Oconee	It depends on the application. If the application is critical and there is a high probability that it will cause a plant trip, we will replace. Symptoms may vary. For less critical applications, we may live with the problem until the card can be recalibrated or repaired.
12	Peach Bottom	Replace card if it can't be calibrated or if a card responds unusually during testing/calibration.
12	Perry	Calibration tolerances have been established using OEM guidance where available, RSE judgment where not. We've replaced components due to excessive drift and unstable op amps.
12	Quad Cities	Unfortunately, marginal components are not usually found during routine maintenance. If a card cannot be calibrated, then it is replaced. If a servovalve does not null bias closed, then it is replaced. If the bypass valves do not open fast enough during bypass valve timing test, then servovalve is replaced. If excessive noise or temperature is noted during calibration, then circuit card is replaced. Servovalve holding current test is good indication of a problem.
12	River Bend	RBS does not have such a process.
12	SSES	Process includes: Excessive drift (input/output data within ± tolerance); history of continued drift; data repeatable, technician & foreman judgment used to determine. Symptoms/behaviors include: observed heat damage, intermittent relays.
12	Vogtle	If there is any doubt about the quality of the part, non-repeatable/erratic components will be replaced.
12	Wolf Creek	If it can be easily replaced on-line, we will do it. If the component is failing and we need to remove it from the circuit without any adverse effects, then we will perform a temporary modification to remove it and then replace it during an outage. We recently had a watt transducer for the PLU circuit beginning to drift. We removed it from the circuit before it failed and lived with it until we could drop to a power level that would be acceptable for replacement.
13A	Bruce	The failures, if any, are usually obvious.
13B	Brunswick	GE/third party. Required if repeat MPFF or loss of maintenance rule function.
13B	Callaway	Attempt on-site analysis; will also use GE.
13B	Dresden	IRI performed our root cause analysis on EHC power supply failure prior to refurbishment. (Corp.) Corporate materials engineering personnel.
13B	Gentilly	On-site with the help of GE, even if most of the time GE does not support Mark II as much as we would like.
13B	LaSalle	Site as well as corporate, most times involving GE.
13B	Oconee	Combination of site, GE and sometimes a third party.
13B	Perry	Whether or not to do root cause analysis is driven by our corrective action process and would be based on plant impact. So far, on-site but would use GE or third party if cause is elusive.

Item	Plant	Comment
13B	Quad Cities	Off-site ComEd testing facility performs failure analysis of circuit cards, relays, and solenoids.
13B	River Bend	RBS, GE, and outside lab have all been used, depending on the nature/severity of the problem.
13B	SSES	Third party—GE, Novatech, Encore, and S. Levy.
13B	Summer	Done by system engineering.
13B	Vogtle	If we do it, we do it in-house. We have had little luck getting GE to do any real root cause. We have not tried third-party sources. Have tried to get failure mode of some components but didn't have much success.
14	Dresden	We did this a long time ago without any problems. We need to start doing this again to help reduce unneeded outage calibrations.
14	Gentilly	Data is collected every day, and we follow the parameters on a day-to-day basis.
14	Perry	ERIS computer data mostly. We don't have a formal procedure for data collection and comparison but think one should be generated so acceptance criteria would be formal. We have connected vendor-supplied data acquisition equipment to acquire data. (Fluke Netdaq is a good system for this.)
14	Quad Cities	Only if a problem is suspected prior to shutdown where data gathering would be useful.
14	SSES	Selected test points/signals for assessment of general system health (e.g., PLU, speed control, pressure control, and load control).
14	Summer	Only if a problem exists and on-line data could be useful in resolving.
14	Vogtle	Temperature monitoring devices. Troubleshooting and comparison for startup data.
15A	Fort Calhoun	"As-found" and "as-left" data from calibration of all EHC corneal circuits is retained. This has been useful for troubleshooting.
15A	Peach Bottom	Only if a failure occurred more than once.
15A	SSES	EHC/TSI power supply DC voltage drift and AC (RMS) voltage ripple during normal operation and includes peak-to-peak AC ripple during refuel outage.
15A	Wolf Creek	EHC pump pressures, fluid sample data, fluid temperatures.
15B	Callaway	Typically, do not trend electronics.
15B	Dresden	IMD system files have trends for MSPS drift.
15B	Limerick	Technicians do some trending.
15B	Maanshan	We measure power supply volts, current, ripple voltage, vibration sensor mils, servovalve characteristic curve, etc. We refer to this data to determine whether or not to replace the element.
15B	Perry	Plan to do more in the future.
15B	Quad Cities	The database does not contain good data; therefore, it is hard to use it as a predictive maintenance tool.
16A	Quad Cities	Weekly; every 2 years for actual test.
16A	Summer	Using oil trip test button.
16I	Vogtle	Not required with proximity probes.
16K	Callaway	Partial monthly—full quarterly.
16L	Callaway	Partial weekly—full monthly.
16M	LaSalle	When unit is < 50% load.
16O	Calvert Cliffs	MTSV test—weekly.
16O	Limerick	Monthly accumulator checks.
16O	Quad Cities	Master trip solenoid valve stroking every week.
17A	Bruce	The design of the electronics caused severe hydraulic oscillations during turbine warming, which caused a line break. The circuit was repaired, and there have been no problems for 7 years. The thrust bearing wear detector has caused a trip, but this seems to have been a one time event that cannot be repeated.
17A	Brunswick	Pressure regulator (Unit 1–1995). Root cause not known.
17A	Callaway	Two false high vibration trips; 2 MOST test trips; 1 TBWD test trip. Last trip in 1992.
17A	Calvert Cliffs	Failed SADI card.

Item	Plant	Comment
17A	Fort Calhoun	An age-related failure of a card-mounted miniature power supply that supplied two pressure transmitters.
17A	Gentilly	Short circuit of electrical trip solenoid valve coil. Bad design of a board, provided as part of the bay 3 meter relay elimination, caused a trip while testing the TBWD on-line.
17A	Hatch	Not recently.
17A	Maanshan	1) EHC 24 VDC power supply capacitor C3 failure. 2)AC-PT-27 transmitter breakdown (Throttle pressure transmitter). 3) EHC electrical trip pilot valve breakdown.
17A	Oconee	Keying a security radio in the vicinity of the EHC caused a trip. Modifications caused interference with electronics—turbine tripped. Low shaft pump discharge pressure on startup. Personnel errors have caused trips (performing maintenance on wrong unit, securing equipment too quickly, not resetting equipment, etc.). Janitorial service sprayed down cabinets, causing a trip.
17A	Peach Bottom	None in the last 4 years. Numerous trips previously.
17A	Quad Cities	Mercury-wetted relay failure caused turbine trip and auto scram in 1993 on false condenser low vacuum signal. Contact failed in the closed position.
17A	River Bend	6/96—+22 VDC power supply failure—inadequately designed voltage regulation circuit. Circuit caused failure of voltage regulator function if the “other” power supply overvoltage device actuated. OEM redesigned voltage regulator circuit board. 10/93—Turbine tripped during TBWD test. Failure of K15 relay (a Deutsch relay). Plant installed a turbine trips bypass switch that is used during this testing. 11/92—Plant SCRAM due to CV motion when SB&PR swapped from the in-service regulator to the backup regulator. Was due to slow drift between channels. Logic design intent was for swap to occur instantaneously to overcome failure of a channel. Slow drift allowed large delta between channels. When error detection sensed that the in-service channel was drifting, it swapped to the backup channel. 12/90—Reactor SCRAM occurred during CIV testing. Numerous attempts had been previously made to eliminate a suspected electronics cross talk problem. The FASV-P ports were orificed to eliminate large ETS pressure changes as the valves’ test switches were released. This modification resolved this problem permanently.
17A	SSES	TSI spurious high vibration trip—vibration amplifier circuit card and vibration detector replaced. GE failure analysis indeterminate as to root cause (1/12 trip logic). Loss of stator cooling high temperature trip—root cause was vibration induced failure of TIC (1/1 trip logic).
17A	Summer	On 2/3/86, the turbine was being rolled at the fast acceleration rate (180 rpm/minute) to 1,800 rpm during a plant startup. At about 400 rpm, a malfunction in the control system caused rapid opening of the control valves, and turbine speed increased to nearly 1,000 rpm over a 30-second period. Steam flow spiked to about 50% of full steam flow, and a rapid drop in stream line pressure occurred. Although stream line pressure stayed above 675 psig, the rate of decrease was sufficient to cause a safety injection on low stream line pressure because of the rate compensation in the circuit. Action was taken to determine the cause of the malfunction, but no problems were identified during troubleshooting or the subsequent startup. GE was brought in to check out the cabinet, and a recorder monitored several test points during the subsequent startup. GE could provide no explanation for this problem, which has never recurred.
17A	Vogtle	Trip in 1988. Happened when stop-go normal button was used during a mechanical trip piston test. Root cause could not be determined. Also, CIVs closed during initial startup activity.
17A	Wolf Creek	Backup overspeed amplifier test malfunction, 2/22/86. Lost house power and PMG swap over relay, 5/28/87. Vibration trips: 1/17/87, 1/20/87, and 1/23/89.
18	ANO	Minimal. Failed load limit circuit.
18	Bruce	Seventy-five percent power for 10 minutes due to spurious valve operation caused by an intermittent fault in a potentiometer.
18	Brunswick	1995 pressure regulator failure on Unit 1. Returned to operation in 3 days.
18	Callaway	Has been very reliable for the last 8 years.
18	Calvert Cliffs	Few days outage over the life of the plant. Alignment problems found during startup.

Item	Plant	Comment
18	Dresden	(Corp.) 1996 approx. 1.2 million MWhrs lost due to EHC (6 units). 1995 approx. 200, 000 MWhrs lost due to EHC (6 units).
18	LaSalle	Lost capacity years ago due to control valve oscillations. Also, had down time due to failed circuitry on several occasions.
18	Limerick	Runbacks to low power for troubleshooting and repair of leaks, etc.
18	Oconee	Twelve hours lost due to broken lug on valve indicator during startup. Ten hours lost due to sticking test solenoids valves on main stop valves and broken lug on MSV-2 servovalve during startup.
18	Peach Bottom	Must reduce power to repair leaks.
18	Perry	Due to not calibrating in our early years, replacing the P/L gate created an offset between SB&PR and EHC. The plant was restricted to 45% for several days in 1993.
18	Quad Cities	Approximately 600,000 lost MWhrs since 1988.
18	River Bend	12/96—Had to operate plant in derated mode due to CV oscillations at 100% power, after implementing LEFM feedwater flow modification. Derate was about 15 MWhrs for about 2 weeks.
18	SSES	Unit 1 1996 unplanned capability loss factor (UCLF)–1.36% (TSI spurious high vibration trip) Estimated Unit 1 1997 UCLF–3.91% (inadvertent bypass valve openings).
18	Summer	On 12/2/89, operations was decreasing turbine load to 90% to perform control valve testing. At approximately 95% load, the load reference motor suddenly drove to the 2% load position, resulting in an uncontrolled turbine runback at a rate of 133% per minute. The start of the runback coincided with use of the Decrease button on the Load Set controls. Subsequent investigation showed that two sets of normally open contacts in the Load Reference Circuit Logic had failed closed and remained closed even after the respective relay cards had been removed from the control cabinet. The failed relays were K5A14, which runs back the load reference motor on Power-Load Unbalance, and K8A38, which causes a runback if 2,800 rpm is not selected on Speed Set. The contacts of these relays are parallel to the Decrease button on the Load Set and provide 24 VDC to relay XK24-1, whose contacts cause the load reference motor to drive in the decrease direction. It was determined that when the Decrease button was pressed and then released, a large reverse voltage inductive kick occurred in the coil of XK24-1, which caused arcing across the contacts of K5A14 and KBA38. When the runback occurred, the arcing across the contacts was sufficient to weld the contacts closed. This failure was a result of two conditions. The first was a design deficiency that did not include any form of surge suppression for the coils of the XK relays and allowed high inductive voltage to be generated during operation of the relays. The second was the replacement of the original 125 VDC (GE PN118D1499-G01) relays with an upgraded new design during MRF 20826. Both K5A14 and K8A38 are new design relays whose contacts are more sensitive to arcing than the original relays. The combination of these two conditions led to this failure; in addition, there have been several failures of relay logic during valve testing, which were probably caused by this combination. This problem was eliminated by adding two series 1N4007 diodes across the coils of each XK relay that is powered by 24 VDC (see MRF 21693). In addition, all 125 VDC relays were replaced per MWR 90I0001 to preclude any future control failures that may have resulted due to degradation of contacts.
18	Vogtle	1) Shell warming circuit set point drift. 2) Test circuit malfunctions—hardware logic.
18	Wolf Creek	Lost approx. 90K MWhrs due to problems identified in #17.
19A	ANO	CV, SV, and CIV stroke testing.
19A	Calvert Cliffs	Control valve test.
19A	LaSalle	Power reductions required for valve testing.
19A	Limerick	Can't test CVs at power because they reclose to fast.
19A	Maanshan	Control valve test before plant power reductions.
19A	Quad Cities	Control valve oscillations at steady-state conditions.
19A	SSES	Derate to 98% for quarterly CV, SV, CIV testing. CV testing cannot be performed between 63%–80% or 86%–92% reactor power to avoid reactor power spikes.

Item	Plant	Comment
19A	Summer	The throttle pressure limiter has frequently caused concern by indicating a limiting condition on the control panel and on the plant computer. The limiter is designed to cause control valves to close as throttle pressure drops below 832 psig. Troubleshooting during the T_{avg} coastdown at the end of Cycle 6 confirmed that a limiting condition was reached as throttle pressure went below 900 psig. This problem was examined by Al Knight of General Electric during the Refuel 5 outage, and no problem was found with the limiter circuit. A further investigation was done during the Refuel 6 outage per ICP-440.013; when applying test signals to the cabinet, the limiting condition was reached at 832 psig. It is unknown at the present time why the throttle pressure limiter responds properly under test but prematurely limits in actual operation. Testing of stop valve 1 on 12/27/92 resulted in a 20 MW drop in load and automatic control rod insertion. Operations suspended the test and wrote ONO 92-088. The cause was traced to inadvertent limiting by the throttle pressure limiter, which automatically stoked the control valves in the closed direction. The throttle pressure limiter has caused occasional computer alarms in the past by going into a limiting condition during steady-state operation, even though throttle pressure was around 910 psig, well above the limiting set point of 833 psig. This problem has been investigated several times by both systems engineering and General Electric without success. Operation of the limiter was monitored during the T_{avg} coastdown at the end of Cycle 7, where the throttle pressure approached 850 psig at minimum, and the circuit never went into a limiting condition. Shel Ableson of GE has suggested our problems may be due to the design of the throttle pressure limiter. The signal from the TPL is low value gated with the signals from the load limiter and the throttle pressure compensator; however, the TPL does not use an emitter follower current amplifier at its output, as the other two circuits do. GE has recommended reducing the limiter's set point with the control panel pot if problems persist, and Operations has adopted this practice. TPL and TPC have been removed.
19B	Fort Calhoun	Shell warm controls are difficult to use.
19B	LaSalle	Had problems with speed control circuit in the past.
19B	Limerick	Operations would like to control pressure at 50 psia.
19B	Perry	Set point is generated from motor-driven potentiometers. After sitting idle, potentiometer becomes dirty and generates a noisy set point. This can cause channel mismatches and transfer between regulator channels. This occurs on S/U and S/D when set point is being changed. Another challenge we've had is a noisy set point caused by the min. pressure set point current amplifier becoming unstable, causing the plant to follow the set point.
19B	SSES	SU—bypass valve sensitivity on pressure set manipulation.
19C	Summer	During the plant shutdown for the Fall 1991 outage, the decrease load rate circuit inadvertently turned itself off and caused a minor (10%) load step decrease. Prior to the start of the shutdown, a recorder had been connected to various test points in the control cabinet, and Operations had set the load limiter to maximum and turned the throttle pressure limiter off to perform monitoring unrelated to the decrease load rate circuit. A limiting condition in either of these circuits will automatically turn off the decrease load rate circuit, but the control setup at the time of the transient ensures that neither limiter was responsible for the step load change. The recorder showed no noise spikes on any of the monitored channels, and there were no clues as to the origin of the problem. Troubleshooting efforts during Refuel 6 and Refuel 7 outages have been unable to reproduce the problem. Presently, Operations is exercising caution when using the decrease load rate circuit by making smaller changes in load set while reducing load, or avoids using the circuit by slowly decreasing the load limiter instead. Problem persists today. Note that throttle pressure limiter has been removed.
19D	SSES	Power changes—in vicinity of CV-4 opening crackpoint.
20	Bruce	Used once in 7 years. There were no difficulties.
20	Callaway	Not any more. Last time used circa 1992 and got fast closure of the IVs. Cause not found.
20	Vogtle	About 1-2 times a year after a component failure or during corrective maintenance. No specific problems.
20	Wolf Creek	For on-line maintenance and troubleshooting.
21A	Gentilly	Throttle pressure is always on at a set point.
21A	Maanshan	Continuous use during normal operation.

Item	Plant	Comment
21B	Callaway	Load limit is kept just above normal load set, so it can be used on load swings or disturbances.
21B	Fort Calhoun	We always operate the load limit when on-line.
21B	Gentilly	Load limiter is remote control by plant computer.
21B	Maanshan	Continuous use during normal operation.
21B	SSES	LL used during CV testing.
21B	Summer	Always use load limiter at 100% power.
21B	Vogtle	Load limiter always in use to allow finer control of power.
21B	Wolf Creek	Normally run on load limit.
21C	Gentilly	Only for FCV testing.
21C	Maanshan	Use only during CV test.
21C	Oconee	First-stage pressure feedback used to control pressure and power swings during CV testing.
21C	Wolf Creek	Stage pressure feedback automatically controls CV position during testing.
21D	Quad Cities	Not normally used at Quad Cities Station.
22	Callaway	No major problems.
22	Dresden	(Corp.) Need PM program (monitoring) to identify and replace degraded electronics prior to failure. Need system calibration procedure improvements.
22	Gentilly	A major problem is when loading in manual mode and during load increase using the load rate circuit. If the operator switches to remote at that time, the load will increase at the valve opening rate, which is very fast. A modification has been written and will be implemented next outage.
22	Oconee	We have been challenged with procedure use and adherence. It is a struggle to put lineup instructions into a format that can be followed exactly while accounting for every situation that could arise during procedure performance.
22	Quad Cities	No major problems with the above.
22	River Bend	GE field lineup instructions are very general. The instructions would be of much more value if specific points/voltages/etc. were specified.
22	SSES	GE field lineup instructions don't always identify <u>all</u> affected signals.
22	Summer	Field lineup instructions from GE are insufficient in detail, vague, or wrong.
23	Browns Ferry	Pressure set points buttons stick. Switches sensitive to foreign material. MTSV push buttons stick—can cause loss of power to logic. Some panel lights are dim.
23	Callaway	No real problems. Valve position meters are cheap and do not return to correct indication.
23	Dresden	(Corp.) Servo, shutoff, and solenoid valve failures. Hydraulic leaks. LVDT joints. Need noise/grounding improvements/checks.
23	Fort Calhoun	Motor-driven controls (such as load set and shell warming) are a bad idea. It is better to have a direct operator/EHC interface.
23	Limerick	Meters stick due to static. No indication of the operation of some switches. Wear out of switch contacts and mechanisms cause problems. Labels could be better. No seal in on electrical malfunction bus. Pots cause problems.
23	Peach Bottom	Fast close during control valve testing was not detectable. New meters solved the problem. Sticking buttons. Can't tell the difference between switches and indicators. MTSV stuck in the trip position.
23	River Bend	Load set MOP has malfunctioned during operating cycle seven. MOP won't raise consistently during attempts to position the MOP with the push button. Plan to replace MOP with digital load set card from after-market vendor in 9/97. It would be much more desirable to have all front standard testing push buttons at the main EHC panel instead of the main control room "ATC" area. Then, the operator could observe all lights at the EHC panel during this testing.
23	SSES	Control room EHC panel connectors difficult to maintain ''made up.''
23	Summer	Primary/backup acceleration amplifiers are very difficult to test/align.
24A	Browns Ferry	F/V card is temperature sensitive.
24A	Peach Bottom	Performed muffin fan upgrade.
24A	Summer	Have seen possible problem with speed control unit LVGs due to temperature-induced drift.
24D	Callaway	Radio transmission is forbidden in the EHC room.

Item	Plant	Comment
24D	Limerick	F/V card causes noise. Megacycler caused noise.
24D	Peach Bottom	Valve motion on fan start.
24D	Wolf Creek	Spurious trip signal in vibration cabinet when resetting alarms. Installed noise suppression and a manual lockout switch to defeat trips when resetting alarms.
24E	Brunswick	Electronics are located in the main control room.
24E	Limerick	Valve position meters drift.
24E	Peach Bottom	Amplifier zero drifts. Acceleration load rate drift on Unit 2.
24E	Quad Cities	Do not allow radio usage near the cabinets. Do not normally see any problems with temperature, humidity, or vibration.
25	Browns Ferry	Regulators switching between channels. Set point bias drift.
25	Callaway	Only fast closure of IVs when transferring to standby turbine control.
25	Peach Bottom	Both A and B in control lights off while using bypass jack.
25	Perry	See #19 response.
25	SSES	Reset of turbine caused turbine to go to 1,800 rpm due to relay race—operator depresses AVC button when resetting turbine. Bypass valves inadvertent opening during pressure set manipulation.
25	Wolf Creek	Primarily when we have a failure of a component (i.e., MTSV).
26A	Browns Ferry	Trimpots are very sensitive. DFGs hard to calibrate.
26A	Bruce	The flow control cards are the most difficult due to the many steps required.
26A	Peach Bottom	DFGs, SLRC, and pressure amplifier time consuming.
26A	Summer	See response to #23.
26D	Limerick	Access at hydraulic skid is poor.
26D	Peach Bottom	Access at hydraulic skid is poor.
26E	Limerick	Operations is reluctant to permit on-line maintenance at the electronics. During refuel maintenance, have to wait for valve work to be completed before some calibration and testing steps can be done.
26E	Quad Cities	Conservative decision making by Operations department. ROs do not allow I&C technicians to manipulate control room switches. This slows down calibration if other work is going on.
26E	SSES	Some poor communication links.
26F	Quad Cities	Must pull DFG and F/V boards to get at some test points and adjustable potentiometers.
26F	SSES	BPV amplifier.
26G	Maanshan	Servovalve.
26G	SSES	DFGs; pressure amplifier.
26H	Browns Ferry	Removing/replacing cards cause a shift in calibration.
26H	Callaway	Numerous relays in the Mark II system, especially T&M. Difficult to test in the system and time consuming to remove and test.
26H	Fort Calhoun	On-line repairs are usually not possible.
26H	Gentilly	Field lineup is done by experienced personnel. Qualification of new people on the system is very difficult with that document. Also, the technicians work seriously on the system once a year.
26H	Peach Bottom	Some test buttons must be pressed in proper sequence in a short time.
26H	Quad Cities	Cannot manipulate system at power. This makes it difficult to troubleshoot because the problem is not always prevalent when the unit is down.
26H	SSES	Cannot simulate normal reactor operating conditions in Condition 4 or 5.
27A	Browns Ferry	Stop valve limit switch problems. LVDTs binding.

Item	Plant	Comment
27A	Callaway	Some problems with valve position control boards. Numerous failures of muffin fans and lights. Moderate failure rate of circuit board relays. Slight failure rate of power supplies. Moderate failure of new ETSV.
27A	Dresden	Meter relays are constantly causing false alarms and failing in the monitor panel. (Corp.) Capacitors; mercury-wetted relays. Electronic card failures are the third largest cause of lost production (MWhrs) by the EHC system at our utility's 12 nuclear units (6 BWR and 6 PWR).
27A	Fort Calhoun	Mercury-wetted relay; DFG.
27A	Gentilly	For the moment, all of the components are showing great reliability and stability.
27A	LaSalle	Op amp adjustments difficult due to wear on potentiometers and aging. Mercury-wetted relays are unreliable.
27A	Oconee	Control valve amp; load reference amp; voltage comparator. Cards appear to drift. They are not difficult to calibrate. May drift due to temperature. This does not cause performance or reliability problems.
27A	Perry	IV position control cards—hi gain so sensitivity to temp. changes causes drift but is not excessive. Light bulbs burn out frequently on monitoring panels.
27A	Quad Cities	Meter relays (burned out light bulbs), GE HQ pressure transmitters and associated demodulator circuit cards (drift), turbine control valve DFG boards (drift and hard to set up), adjustable potentiometers on circuit cards.
27A	River Bend	Panel fan flow switches give false alarms more frequently than desirable. Incandescent light bulbs in EHC power/monitoring/test panels burn out frequently. These bulbs should be changed to LEDs to lower the failure rate.
27A	SSES	Bulbs, fans, wetted-contact relays, meter relays, TSI TTs, valve limit switches, servos.
27A	Vogtle	Relays on trip and monitoring panel.
28	Calvert Cliffs	Failure of SADI card was attributed to aging.
28	Dresden	Aging has degraded the capacitors in the power supplies. (Corp.) Card failures.
28	Fort Calhoun	The system seems to be more temperature sensitive. The amount of "as-found" out of tolerance has increased.
28	LaSalle	Calibrations becoming more difficult. Potentiometers have bad spots.
28	Maanshan	1) 3TM2-S101PS1; 2) 3TM2-S101PS2; 3) 3TM2-S101PS3; 4) 3TM2-S101PS4; 5) 3TM2-S101PS5.
28	Quad Cities	Mercury-wetted relays, 3 kHz oscillator boards, and transistors seem to be giving us problems. Op amps have failed on occasion, also. Adjustable potentiometers on circuit cards.
28	SSES	Increased power supply maintenance. Problem with electrolytic capacitors. Mercury-wetted relay hang-ups.
28	Vogtle	Relay failures.
29	Calvert Cliffs	SADI card. Undersized transistor installed.
29	Limerick	F/V card had wrong capacitor installed.
29	Quad Cities	IC op amp cards, voltage comparator cards, and SLRC cards.
29	River Bend	Primary speed LVG card drifted after initial calibration during replacement of card. Had to recalibrate card.
30D	Vogtle	Field lineup instructions.
30E	Brunswick	There are a considerable number of drawing errors in the vendor documents.
30E	Gentilly	Too general, not site specific. Many abbreviations are used but not adequately defined.
30E	River Bend	See response to #22.
30E	SSES	See response to #22.
30F	Dresden	System calibration procedure needs improvement. (Corp.) Would like 3-step calibration: 1. Calibration checkout—identify which portion of the system requires calibration (e.g., speed control, pressure control). 2. Calibration of each subsystem identified in step 1. 3. Integrated test. Signal inputs and signal outputs to assure they are calibrated.
30F	Fort Calhoun	We use our own procedures. They are pretty good.

Item	Plant	Comment
30F	Quad Cities	Procedure needs to be revised to add additional PMs to mercury-wetted relays, time delay relays, and XK relays.
30F	SSES	Have not developed a comprehensive SSES specific procedure similar to GE field lineup.
30F	Summer	See response to #22.
31	ANO	Specialized system training.
31	Bruce	Training is done in-house in a classroom from time to time and as a journeyman/apprentice relationship.
31	Callaway	Instrument shop provides a pretty good electronics training course. Operations training has improved and is pretty good.
31	Calvert Cliffs	Every 2-3 years a contractor is brought in to teach the course.
31	Dresden	(Corp.) Periodic when initiated by site.
31	Fort Calhoun	Two weeks of system-specific classroom training, plus on-the-job experience.
31	Gentilly	No training for system engineers. Training given by system engineers to technicians. Training given by qualified technicians to other technicians.
31	LaSalle	Training using only documentation.
31	Oconee	Class is offered once every 2 years for technicians. We use an outside vendor for training. Operators train on simulator, and this is ongoing.
31	Peach Bottom	S. Levy classes and simulator training.
31	Perry	Training has been provided by our training organization, by OEM, and by third-party vendors. All have used documentation only, no simulation.
31	Quad Cities	Vendor comes in periodically (4- to 6-year intervals) to provide specific training. No other training is provided to technicians.
31	River Bend	I&C technicians train on EHC about every two years. Recently most of the technicians attended a Mark I EHC course given by a sister plant, then were trained in the differences between Mark I & Mark II here at RBS. The effectiveness of this approach will become obvious in the upcoming outage 9/97.
31	SSES	EHC initial/continuing training (~ 3 weeks) developed for SSES by third party (General Physics, S. Levy). Initial/refresher training taught approx. every 5 years.
31	Vogtle	Small group of technicians receive extensive training. Training using system documentation.
31	Wolf Creek	System documentation and OJT.
32	Dresden	(Corp.) Limited qualified technicians.
33	Callaway	GE field lineup could be more user-friendly.
33	Dresden	(Corp.) Fewer cards by upgrading system; 3-step calibration process above (see item 30 comment).
33	Gentilly	Hardware: use of standard components. Procedures: more detailed procedure with identification of the board numbers in the text, no use of abbreviations.
33	LaSalle	A good turbine simulator to test system response would be helpful.
33	Limerick	Perform all calibrations without having to stroke the valves.
33	Perry	Digital set point pots, with elimination of minimum pressure set point circuit.
33	Quad Cities	Quad Cities performs a final functional test at end of each outage to verify that adjustments made during the outage were correct and that system is operating properly.
33	River Bend	Digital acquisition equipment would provide continuous monitoring of critical parameters, proactive possibilities, and enhanced “post mortem” troubleshooting.
33	SSES	States links SSES procedure (step-by-step) from beginning to end to tune-up EHC (similar to GE field lineup) banana jacks better recorders than L&N, better higher resolution indicators on EHC panel, development of an “off the shelf” generic circuit board that could be configured (jumpers, pins, etc.) for multiple applications, direct replacement of power supplies.
34	Dresden	(Corp.) Hydraulic test stand for valve checking prior to installation.
34	Gentilly	EHC/turbine simulator, which simulated the field when connected.
34	Limerick	Use good frequency generator and analyzer.
34	Quad Cities	An EHC simulator that would simulate speed, load, and pressure.
34	SSES	Use extender card with switches. Would like a simulator for Rx. power

Item	Plant	Comment
35	Callaway	We have gone to 2/3 logic on most trips. We have modified most trip tests to make them trip proof.
35	Gentilly	Every modification has caused unexpected behavior (e.g., an unexpected alarm during testing).
35	Quad Cities	Have not performed many upgrades to the electronics at Quad Cities station.
35	River Bend	RBS installed switches in the CIV testing circuits to eliminate a suspected electronics “cross talk” problem. The problems were later determined to have been caused by lack of FASV-P port orifices. RBS installed a turbine trips bypass switch that did not block the redundant “close valves” signal, so it was ineffective. It was modified such that the “close valves” signal is also interrupted when the switch is in the bypass position.
35	Summer	When new design 125 VDC relay cards were installed, inductive kick from XK relays caused contacts to weld closed! See response to #18.
36	SSES	Additional PMs require increased outage time to perform.
37A	Callaway	We don’t have troubleshooting procedures specifically for EHC. We rely on specific instructions by system engineers, foremen, and GE.
37A	Calvert Cliffs	Troubleshooting procedure is developed separately for each problem.
37A	Gentilly	Do troubleshooting procedures exist?
37A	Limerick	Technicians prepare a troubleshooting plan for a specific problem. Measurements during plant operations is not permitted. Poor communication with operations (problem descriptions too general). Use of data from plant computer is helpful.
37A	SSES	Go by field lineup and tech expertise.
38	Browns Ferry	PMG failures hard to detect. New F/V card had wrong capacitor.
38	Dresden	Sometimes nothing found after failure.
38	Fort Calhoun	This is always difficult when doing on-line troubleshooting.
38	LaSalle	Had a failed F to V that was failing only when the turbine was actually running at approximately 1,750 rpm. This made troubleshooting difficult.
38	Limerick	Control valves went closed. Spent 1 week trying to diagnose but could not find problem.
38	Peach Bottom	A dual ground caused mechanical trip solenoid to actuate.
38	Quad Cities	Erratic high frequency oscillations (15–20 Hz noise) on one turbine control valve. Finally determined to be card #1 of 3 kHz oscillator for that particular turbine control valve.
38	River Bend	As stated above, (see response #35) numerous troubleshooting attempts were undertaken to eliminate a suspected electronics cross talk in the CIV testing circuits. The problems were later determined to have been caused by lack of “P” port orifices in the FASVs.
38	SSES	If related to wiring or noise related problems. TSI high vibration trip bypass valve inadvertent opening events.
38	Summer	Spurious alarms (First out panel, “EHC electronics malfunction” annunciator, “Loss of DC to EHC cabinet” annunciator). See also response to #19A and #19C.
38	Vogtle	Troubleshooting relay logic.
39	LaSalle	More test points on front of cards.
39	Limerick	Eliminate blind relays. (Relays where state is hard to determine.)
39	Quad Cities	Isolators on circuit card test points.
39	River Bend	Adding a digital acquisition module to monitor key EHC system parameters. This would provide the opportunity to proactively address developing system problems before the problems become threatening.
39	SSES	Use controlled prints (training manual documentation). Use switches to defeat turbine trips
39	Vogtle	Relay logic matrix.
40	Browns Ferry	Data from plant computer. Strip chart recorder.
40	Bruce	Digital storage oscilloscope; a very accurate voltage source; Multi Meters help a lot.
40	Callaway	A test board for testing the multiple relays that are utilized in the controls, especially trip and monitoring.
40	Perry	Obtaining real time data at multiple points is essential for on-line troubleshooting. Data acquisition equipment is very useful.

Item	Plant	Comment
40	Quad Cities	Basic strip chart recorder, DVM, and battery-operated oscilloscope.
41A	Limerick	Thirteen to 26 weeks.
41A	Peach Bottom	Up to 52 week lead time.
41B	Dresden	(Corp.) Servovalve quality problems (new / rebuilt).
41B	Peach Bottom	Fifty % failure rate on new cards from drive system dept.
41C	Peach Bottom	TSI card not compatible.
41D	Callaway	Lambda power supplies are good, but unavailable—we repair on-site.
41D	Gentilly	Potter Brumfield time delay relays. GE is trying to see what the demand is for these parts and find a company to manufacture it. If it is not successful, we will try to find another vendor.
41D	Maanshan	We are concerned that the Mark II power supplies are not available and don't have old EHC spare supply to replace it.
41D	River Bend	Load set MOP. This is no longer available from the OEM or the OES. It will be replaced with a digital load set card installed in a spare card slot location. EHC power supplies originally manufactured by Lambda are no longer available. We plan to perform extensive testing of the installed power supplies as opposed to periodically replacing the power supplies.
41E	Bruce	No difficulty finding parts for repairs.
41E	Fort Calhoun	Circuit cards are soon to be unavailable. We have purchased a set of used cards from a retired system. There are third-party vendors that can test / refurbish them.
41E	Oconee	We bought spares from GPU when they upgraded to a Mark V. TSI speed channel instrumentation is no longer readily available. We had an outside vendor build a transformer to replace a Triad P01A model. GE is special building the speed amp card for us because certain components on the card are obsolete.
41E	Perry	SB&PR parts are sometimes hard to come by. Because few were made, not as readily available as EHC parts. Future support from GE on both Mark II EHC and SB&PR is being addressed by BWROG. At this time, not sure of final long-term solution.
41E	Quad Cities	Price of replacement circuit boards from GE are ridiculously high! Plan to investigate options available from NOVATECH on replacement op amps, relay boards, voltage comparator boards, and SADI boards.
41E	SSES	GE letter regarding parts obsolescence (soon to be rescinded; but for how long?). Will go to alternate vendor, if necessary. (e.g., Lambda power supplies, 24 VDC relays require Potter Brumfield base changeout, GE indicators face change, NAMCO limit switch "guts" replacement require purchasing whole switch).
41E	Wolf Creek	We will either go to a different vendor for new or refurbishment. Another option we have is that many other plants have the same system with spares—we use one another.
42	Bruce	As long as basic electronics parts are available, repairs can be completed. At the current rate, our spares should last more than 10 years.
42	Brunswick	Spare parts inventory was recently updated due to indications that GE may go to a repair-only support.
42	Callaway	We try to keep 1 of each controller board, power supply, fan, light, and relay. Share parts with Wolf Creek. Support next 7-10 years with in-house repair.
42	Dresden	(Corp.) Have spares. Will start to run short as aging failures occur.
42	Fort Calhoun	We are getting involved in a pooled inventory program (utilities services alliance). We have an extensive inventory of circuit cards and pump parts.
42	Gentilly	We have almost 80% of the EHC in spare parts. Lifetime of the plant.
42	LaSalle	Have spares for most all cards. This may support us for years if we can get cards rebuilt, but if aging requires replacement of multiple cards, we are in trouble.
42	Oconee	We have purchased several items from GPU due to their upgrading. We could most likely support our present system for 10-15 years.
42	Peach Bottom	One to two year supply.
42	Quad Cities	Parts inventory status is poor. ComEd has a central warehouse so parts for Dresden, Quad Cities, and LaSalle can be shared.

Item	Plant	Comment
42	River Bend	Some cards are kept in stock. About 20 Deutsch and 20 Potter Brumfield relays are kept in the warehouse. How long plant operation could be supported is unknown.
42	SSES	Fair (because we can rework some boards).
42	Vogtle	We have spares for all items. We also have an entire spare cabinet from a canceled plant.
43G	Bruce	All is done in-house.
43G	Perry	Training and lineup support during a previous RFO.
43G	Quad Cities	Have used S. Levy for on-site training. Have used Integrated Resources, Inc. for power supply rebuilds. Considering Novatech for source of EHC cards and repair of existing cards.
44A	Bruce	Usually do not require vendor assistance. Any technical inquiries usually took too long for a response.
44A	Callaway	Yes on the local level. Response from GE Schenectady is sometimes slow.
44A	Calvert Cliffs	No. GE doesn't respond in a reasonable time, if at all.
44A	Dresden	(Corp.) GE technical personnel shorthanded and overloaded.
44A	Gentilly	It is harder today to get timely and accurate responses. We did a modification of the EHC and are waiting for technical answers for 1-1/2 years. We still do not have an answer.
44A	LaSalle	GE has been very good at providing timely response.
44A	Oconee	GE does respond, but they are extremely slow. Most inquiries have to be sent to engineering. We do not have a technical contact anymore. Alternate vendors respond sooner than GE. In cases where it is appropriate, we use alternate vendors.
44A	Perry	Accurate yes, but not necessarily timely.
44A	Quad Cities	Vendor responses from local GE office are usually quick if Schenectady does not need to get involved. Responses from Schenectady are very slow. It is a detriment that we cannot call GE Schenectady directly.
44A	River Bend	Yes. In general, we have found GE personnel to be very responsive, especially when we are involved in a plant-threatening situation. Their solutions have usually been very effective. We have also found an after-market vendor, Novatech (marketed to nuclear by S. Levy, Inc.), to be very responsive when we needed to replace our CV position control cards with digital position control cards during the last RF outage.
44A	SSES	Yes, GE Schenectady has been very helpful as well as Encore, Novatech, and S. Levy.
44A	Vogtle	Yes. On-site representative eliminates contact time.
44B	Brunswick	Yes. We normally use MD&A for technical assistance.
45	Browns Ferry	1,200 hours for refuel alignment.
45	Callaway	For electronics only, on-line 20 man hours; refuel outage 200 man-hours.
45	Hatch	Operations: Testing, fluid, operator time $200,000 per cycle. Maintenance: Outage support, filter changes, calibration $750,000 per cycle. Engineering: Plant system/team engineer, A/E modification, planning 150,000 per cycle.
45	Limerick	700-800 hours per refuel outage; 1/2 electronics, 1/2 mechanical.
45	Peach Bottom	400 hours for electronics and 300 hours for mechanical each refuel outage.
45	SSES	1996 Unit 1 I&C maintenance man-hours—2396 (refuel outage year). 1996 Unit 2 I&C maintenance man-hours—806 (non-refuel outage year).
46	Browns Ferry	Ground offsets cause problems. System configuration not always clear.
46	Bruce	We have 4 identical units that have outages every 2 years, so people are looking at the system every 6 months. Since the people do not change, they have considerable experience in the testing and repair of the system. EHC has been quite reliable and a minimum source of problems.
46	Callaway	Our electronics have been reliable for the last 8 years. We have made many improvements with in-house design changes on our trip inputs (2/3) and in our test methodology.
46	Dresden	The system has performed well at Dresden, which makes it hard for technicians to gain exposure to system problems. (Corp.) Need to use new technology to improve card reliability (fewer cards, better components). Need storage requirements for cards. Need checkout procedure for cards prior to installation. Need PM program to replace cards prior to failure. EHC is a major concern for my company based on the number of failures and lost generation it has caused.

Item	Plant	Comment
46	Fort Calhoun	Our system has been very reliable. You need good calibration and/or test procedures, and you need to use them every refuel outage.
46	Gentilly	In general, EHC electronics are very robust, accurate, and reliable. Because of aging, the number of failures will increase. If the component is one we don't have in spares we could have problems finding it because we know some parts are obsolete, and GE offers no replacement or solution. When I compare EHC Mark II to Mark V control that we have at a gas turbine plant, I prefer the reliability of Mark II and its robustness.
46	LaSalle	Overall, a good design for its time. Aging may cause problems that we cannot deal with in years to come.
46	Limerick	Ground offsets cause problems. Involved in a program to determine feasibility/benefit/extent of upgrading system.
46	Oconee	Our system has proven to be reliable despite the issue of aging. We perform a complete system lineup each refuel outage, and all of our test criteria are extremely tight!
46	Perry	Over all, I think Our EHC and SB&PR systems operate well, with few problems. My gut feeling is that supporting the Mark II cabinet in the future by card replacement and/or redesign will be adequate. I'm not sure that will be as practical for the SB&PR cabinet.
46	Quad Cities	We need to get a handle on circuit card PMs/replacement intervals. What components on the circuit cards are most prone to failure (i.e. transistors, capacitors, resistors)? Has anyone replaced mercury-wetted relays with solid-state relays? NOVATECH appears to have some attractive replacement boards for the Mark I EHC system. We need to somehow qualify these circuit boards for use at nuclear sites. The cost of GE spare circuit boards is excessive. Ground potential between the different bays within the EHC cabinets is getting to be a bigger problem. The EHC system at Quad Cities Station generally is reliable, if properly maintained.
46	River Bend	In general, the GE EHC Mark II system is a very well-designed, reliable system. We have no plans to replace the Mark II system at this time, due to the large cost and complexity involved in such a modification. At the present, we are planning on replacing components as the need arises.
46	SSES	Aging components. Hardware degradation causes system performance degradation and transients; not able to identify "failed" component(s). Logic is not fault tolerant—1 out of many trips (e.g., TSI vibration)—minimal redundancy.
46	Summer	Although there is no connection to a remote dispatcher, the logic for the Remote Auto mode is wired in the cabinet. On two different occasions, closing the generator breaker caused the controls to swap from Manual to Remote Auto, and the operators were not able to increase load set until the problem was detected. Pressing the Manual button restored normal control. We have not been able to reproduce this problem while troubleshooting. Next outage we will remove all circuits and logic that involves Remote Auto mode. At our request before initial plant startup, GE added a Decrease Load Rate circuit such that load may be decreased at 0.5%, 1%, 3%, or 5% per minute. While in operation, this circuit sometimes "turns itself off," which causes a step decrease in load from the present value to the Load Set. Have not been able to reproduce while troubleshooting. Problem has continued after removal of Throttle Pressure Limiter. We experience frequent spiking on the Indicating Relays for House Power/PMG +30, -22 and +24V power supplies. Never see this problem on 3 khz oscillators, however. Throttle Pressure Limiter would become limiting during operation, even with pressure well above the set point. Circuit worked perfectly during troubleshooting. TPL and TPC were removed in 1994. Occasionally get EHC Electrical Malfunction alarm or Loss of DC to EHC Cabinet alarm for no reason. Sometimes first out panel goes into alarm for no reason.
46	Wolf Creek	The system has been generally reliable. So far, replacement components have been available. Going to the proximity probe vibration monitoring system (IRD 5915) has eliminated nuisance trips and has been the most effective modification we have implemented to date. During system alignment, noticeable drift of the calibration settings has been observed due to temperature changes.

APPENDIX F
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