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Westinghouse Nuclear Energy Systems

WCAP-10162

EVALUATION OF IMPACT OF REDUCED TESTING OF TURBINE VALVES

September, 1982

APPROVED: ______________________

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1.0 INTRODUCTION AND SUMMARY

Historically, Westinghouse has recommended that turbine valves be tested periodically. A weekly test recommendation originated in the mid-1950's primarily as a result of service experience associated with fossil plant application at that time and in recognition of the importance of reliable turbine generator operation as it relates to operating personnel and equipment protection.

The importance of frequent valve testing to maintenance of the integrity of systems necessary for the safe operation of nuclear plants has never been clearly established. Nevertheless, the periodic valve testing recommendation has evolved into a license requirement for certain recent nuclear power plants by virtue of its inclusion as part of plant technical specifications. The technical specification requirement appears to be arbitrarily applied-in some cases - weekly test intervals, in others - monthly, and in still others - no requirement at all.

Furthermore, Alabama Power Company has indicated that periodic valve testing as a license requirement poses a not insignificant economic burden arising from the necessity to reduce plant power on an inflexible schedule, the potential for tripping the plant off-line with the attendant undesired cycling of plant equipment, and the associated quality control measures needed in performance of a license condition.

For these reasons, Alabama Power Company requested that Westinghouse evaluate the need for periodic turbine valve testing on the Farley Units as a licensing requirement as distinct from equipment and personnel protection. This report documents the results of that study and forms the basis for the conclusion that periodic on-line valve testing is not warranted as a licensing requirement and can be eliminated from the Farley plant technical specifications. This conclusion is supported by the following:

A. There is no indication that on-line valve testing influences valve reliability or failure rates. Except where deposits are involved, valve exercise does not arrest degradation leading to a recognized valve failure mode and has little demonstrated value in detecting an incipient condition leading to failure. In other words, valve testing primarily yields a binary result, i.e., the valve has failed or it hasn't.

B. The primary benefit of valve testing is a calculated improvement in valve availability due to the potential for detection and correction of failed valves.

C. The turbine trip system is a highly reliable feature and trip unavailability is extremely low, even without on-line valve testing.

D. Periodic valve inspection and maintenance is of primary importance to the detection and correction of valve failure precursors and, hence, to assuring low valve failure rates during plant operation. In that regard, periodic valve inspection continues to be recommended as a highly effective means of assuring turbine trip reliability.

E. Transients imposed on the plant due to failure to trip the turbine even under postulated accident conditions are not severe and in no case constitute a significant contribution to overall public risk.

F. Alabama Power Co. has indicated that the cost associated with periodic on-line valve testing as a license requirement can be significant.

G. Alabama Power Company has indicated that the economic interest of the operating utility to assure turbine trip reliability circumscribes any need for specific licensing requirements.

Westinghouse continues to recommend periodic on-line valve testing for reasons of equipment and personnel protection.

2.0 TURBINE SYSTEMS AND MAIN STEAM LINE ISOLATION VALVES

The turbine system is composed of many individual but interrelated systems that function to control and protect the turbine. The turbine valves control steam flow into the turbine and isolate the turbine in the event of adverse conditions. The turbine valves are themselves controlled by a combination of electrical and hydraulic systems. To understand the significance of eliminating the valve test licensing requirement, it is beneficial to discuss the various systems and their interrelations. This section of this report provides an introduction to the turbine systems and additionally, the main steam line isolation valves (MSIV). The following discussions are particular to the Farley turbine generator complex.

2.1 TURBINE AND VALVES

The Farley turbine generator is designed to convert the thermal energy of the steam generated by the NSSS into electrical energy. It consists of a Westinghouse 1800 rpm, tandem-compound, four-flow exhaust turbine with 44-in. last stage blades mechanically connected to the electrical generator. The turbine is designed at maximum calculated flow to accept up to 11,710,478 lb/hr of throttled steam at a pressure of 750 psia, temperature of 510.9°F and 0.4 percent moisture for a maximum output of 895,843 kw by the generator. It is intended for a base loaded operation with capabilities for load following when required.

Saturated steam from the steam generators flows through a double-flow high-pressure turbine and then through four combination moisture separator-reheaters (MSRs) to two double-flow, low-pressure turbines which exhaust to the main condenser. There are two stages of feedwater reheating off the high-pressure turbine and four stages of feedwater reheating off the low-pressure turbines.

The ac generator is a direct-coupled, 60 cycle, 3-phase, 22,000 V unit

rated at 1,045,000 KVA at 0.85 power factor and has a short circuit ratio of 0.58. The generator shaft is oil sealed to prevent hydrogen leakage. The generator has its own shaft-driven excitation equipment.

The turbine lubricating oil system supplies oil for lubricating the bearings. Typically a bypass stream of turbine lubricating oil flows continuously through an oil conditioner to remove water and other impurities.

High pressure steam enters the turbine through four throttle valves and four governor valves. Two turbine throttle and two governor valves form a single assembly called a steam chest. There are two steam chests. The steam exhausts from the high pressure cylinder, flows through the reheaters and re-enters the turbine through four reheat stop and four interceptor valves.

The turbine is equipped with an emergency trip system which is designed to trip the throttle, governor, reheat stop and interceptor valves to a closed position in the event of turbine overspeed, low bearing oil pressure, low vacuum or thrust bearing failure. An electric solenoid trip is provided for remote manual trips and for various automatic trips.

2.2 TURBINE CONTROL AND PROTECTION SYSTEM

The turbine generator system is equipped with a digital electrohydraulic (DEH) control system to control steam flow to the turbine. The controller consists of seven (7) functional subsystems as follows:

A. Digital reference system
B. Primary speed channel
C. Throttle valve positioning system
D. Transfer control
E. Governor valve positioning system
F. Manual controllers and error detectors
G. Auxiliary speed channels

The digital reference system replaces the normal speed/load changer motor. It is an all solid state system using digital logic. The control for the digital reference consists of a setter/counter comparator, pulse generator and up/down reference counter. The up/down counter controls solid state switching to develop the actual reference voltage. The reference display will read out the setting of the up/down reference counter.

This digital reference approach permits the selection of desired speed and acceleration rates.

The primary speed channel uses signals proportional to the speed obtained from a variable reluctance pickup coupled magnetically to a notched wheel on the turbine rotor. These pulses are converted to a digital speed number in the software. The difference between speed and reference is the primary input to the valve positioning systems.

The throttle valve system consists of an automatic controller and position controls for each valve. The voltage output of the automatic controller establishes the desired valve position and is proportional to the speed error. The speed error input to the throttle valve system provides wide-range speed control during starting. All throttle valves are positioned in unison during starting by means of individual servo amplifiers.

Control of the unit is transferred from the throttle to governor valves prior to synchronizing.

The governor valve system is similar to the throttle valves. The input voltage to the servo amplifiers is derived from the automatic controller. By individually biasing the input of the servo amplifiers, the governor valves are positioned in sequence as required by the turbine design requirements.

The manual controllers with automatic tracking serve as a backup and provide direct operator control over valve position. In the event of

certain contingencies, such as loss of the computer, the control of the unit is switched automatically to the manual backup controllers. The manual control mode permits on-line maintenance of input channels and automatic controllers.

An auxiliary speed channel (part of the overspeed protection controller) converts the frequency pulses generated by a separate variable reluctance pickup to a proportional analog signal for the control of overspeed. The overspeed protection controller operates to close the interceptor and governor valves when the turbine speed becomes excessive, but has not attained tripping speed. It will also operate when there is an excessive imbalance between turbine load estimated from crossover pressure and generator output measured with a watts transducer.

The steam flow is controlled at the main and reheat inlets by conventional valve arrangements. The position control actuators for each valve are of the electrohydraulic (EH) type. A separate hydraulic supply system delivers high pressure fluid to the actuators. This fluid pressure, acting on the actuators, produces the valve positioning forces. The DEH controller computes control signals to position the valves by comparing speed, first-stage pressure and generator-output with reference values.

The high pressure fluid supply system is of the unloading type and is completely separate from the lubricating oil system. A dual pump system is used with one serving as a complete backup. The backup pump starts automatically from low header fluid pressure.

The high pressure fluid trip headers connected to each valve actuator assembly are controlled by a diaphragm operated emergency trip valve and solenoid valves.

Turbine trip is accomplished by dumping auto stop oil which, in turn, dumps EH fluid initiating quick closing of throttle, governor, intercept and reheat stop valves. The interface between auto stop oil and EH fluid is realized utilizing a diaphragm valve and in backup, an auto

stop oil pressure switch operating a solenoid valve in the EH fluid system. Typical installed turbine trip signals are low vacuum, low bearing oil, high thrust bearing wear and as discussed in section 2.5, turbine overspeed. A solenoid trip and solenoid trip valve allow remote tripping for normal turbine shutdown, turbine trip on reactor trip, etc. At Farley, this remote trip capability is also used to trip the turbine whenever an electrical fault occurs that causes generator output breakers to open. An additional feature is an interlock which delays opening of generator output breakers for 30 seconds following turbine trip for reasons other than electrical fault. During this period the turbine is allowed to motor and turbine speed is governed by grid frequency.

2.3 TURBINE OPERATION

Operation of the turbine-generator as described herein relates only to the unit and does not cover the numerous operator actions required in other areas of the plant. With the unit at rest awaiting startup, the first step is to place the unit on turning gear to enable the operators to check that the eccentricity of the high pressure rotor is within acceptable limits. Before admitting steam to the turbine and rolling off turning gear, the unit is latched so that the governor, reheat stop and interceptor valves fully open. The throttle valves remain closed. Once these steps are completed, the unit is rolled to approximately 1700 rpm. During this period the governor valves are fully open and speed of the unit is controlled by pilot valves in the main plugs of the throttle valves. At 1700 rpm speed control is transferred to the governor valves and the throttle valves go to the fully open position. Speed is then increased to 1800 rpm, the unit is synchronized to the system and is ready to be loaded as required by system demand. Once the unit is connected to the system, load is regulated by the governor valves with throttle, reheat stop and interceptor valves in the fully open position.

Whenever the unit is operating under load, the DEH control system positions the governor valves as required by load demand signals and can

operate the unit in the integrated plant control mode, the turbine follow mode or the reactor follow mode as required.

Time required to roll a unit to speed and to make specific increases or decreases in load is governed by operating instructions provided by the turbine-generator manufacturer.

Shutdown of the unit is usually accomplished using these same instructions by unloading the turbine to a predetermined low load and manually tripping the unit. By using this procedure, the operator is able to exercise many of the components of the trip system thus enhancing the likelihood of detecting a potential malfunction before it occurs on an emergency demand.

When the unit trips the sequence of events will be influenced by the source of the trip signal. Usually, if there are no malfunctions, a signal causing the turbine to trip first, followed by the generator trip will result in lower overspeed than if the generator trips first. In addition, a short period of deliberate motoring will further limit overspeed in a trip initiated through the turbine trip solenoid. Thus, the sequence of events and the resulting overspeed are largely dependent on the trip signal source and the unit load. For example, in the event of a large loss of load, two event sequences can be considered:

A. The loss of load transient indirectly causes a reactor trip which in turn, trips the turbine and 30 seconds later, the generator output breakers open.

B. The loss of load occurs due to an electrical fault which causes the generator output breakers to open and the turbine to trip which trips the reactor.

Through the reactor and turbine trip and generator ouptut breakers open in either event, initial turbine overspeed would be more probable in case B than case A. For case A design overspeed is unlikely.

2.4 TURBINE OVERSPEED

The Digital Electro-Hydraulic Control System contains a turbine shaft speed transducer and is the basic control system for turbine overspeed. At 103 percent of rated shaft speed this system releases the electro-hydraulic fluid pressure to move the governor and interceptor valves toward the closed position in an attempt to maintain shaft speed at less than the trip speed.

Backup control is supplied by an overspeed trip valve and mechanical overspeed trip mechanism which consists of a spring-loaded eccentric weight mounted in the end of the turbine shaft. At 111 percent of rated shaft speed, centrifugal force moves the weight outward to mechanically actuate the overspeed trip cup valve which dumps auto-stop oil pressure and in turn releases the electrohydraulic fluid pressure to close the throttle, governor, reheat stop and interceptor valves. The supply steam pressure acts to hold the throttle and governor valves closed.

Upon loss of the EH fluid pressure an air pilot valve closes the extraction nonreturn valves to the feedwater heaters having valves in their extraction lines.

The secondary backup overspeed control is provided by the electro-hydraulic control system if the turbine speed exceeds approximately 111.5 percent of rated speed. At this point the solenoid trip is energized to dump the auto-stop oil which in turn dumps the EH fluid pressure closing the throttle, governor, reheat stop and interceptor valves.

Under normal operating conditions, turbine speed is maintained at 100% of rated speed, generally for domestic units being 1800 rpm for a nuclear plant and 3600 rpm for a fossil plant, and is controlled by the system. If for any reason the load is lost and the circuit breaker opens, turbine speed will increase above rated speed. Loss of load above 30 percent initiates the overspeed protection controller to close all the governor valves and interceptor valves. Simultaneously, the main speed governing system initiates closing of the governor valves in

response to a signal indicating overspeed. In addition, if the turbine speed exceeds 103% of the rated speed the overspeed protection controller signals the governor valves and interceptor valves to close. If the command of the overspeed protection controller is properly executed, all the governor and interceptor valves will be closed and the turbine speed should be kept below 111%. If some of the governor and interceptor valves are not closed, the turbine speed will continue to increase, and at approximately 111% of rated speed the mechanical emergency trip device commands all throttle, governor, interceptor and reheat stop valves to close. At approximately 111.5% (i.e., almost simultaneously) the electrical emergency trip device commands all the valves to close. If all the steam inlet valves are closed by an emergency trip mechanism, the turbine speed should not exceed the design overspeed of 120%. However, if the steam continues to flow into the turbine due to some malfunction, the turbine speed will continue to increase beyond the 120% level, and could accelerate to destructive overspeed of approximately 195%.

Design Overspeed

The turbine speed will reach design overspeed if:

A. During normal operation load is lost, the output breakers open and a turbine trip does not occur at event onset.

B. Both the speed control and overspeed protection systems fail to close at least one or more governor valves or one or more interceptor valves.

C. The emergency trip system functions properly and interrupts the steam flow into the turbine.

Intermediate Overspeed

The conditions that lead to 130% of rated speed, given a full-load system separation are:

A. All throttle or governor valves are closed before design overspeed is reached.

B. One or more steam lines from the MSR's to the LP turbines remain open after the unit trips.

Destructive Overspeed

The turbine speed may reach the destructive overspeed if the following events occur simultaneously:

A. System separation with sufficient steam supply into the turbines, e.g, this can happen if the load is lost and the breaker opens during normal operation, and

B. A combination of failures in the overspeed protection and emergency trip systems, causing a high pressure turbine inlet to be kept open.

Since the destructive overspeed condition can occur only if steam continues to flow to the high pressure turbine, only the governor and throttle valves need to be considered. For this reason the interceptor and reheat stop valves need not be considered for the destructive overspeed condition.

2.5 MAIN STEAM LINE ISOLATION VALVES

The main steam isolation valves are installed in the main steam lines from the steam generators. For the Farley units, two valves are installed in each main steam line, downstream from the safety relief valves, outside the containment.

The isolation valves are 32-in., 600-lb, full-flow, swing-check, nonreturn-type valves with pneumatic actuators. Each valve is provided with air supply and vent piping with solenoid valves as shown in Figure 2-3.

During normal plant operation the valves are kept open against a spring force by air pressure over the piston in the actuator cylinder. Upon receipt of an engineered safety features actuation signal or manual trip signal, the air pressure in the cylinder is relieved and the valve is closed by action of the spring to stop the forward flow of steam through the valve.

Plant instrument air at 80-100 psig pressure is supplied to the actuator cylinder. Each of the redundant isolation valves has its own means of closing and venting the air supply to relieve the cylinder pressure and close the valve. Each isolation valve is provided with a normally open solenoid valve in its air supply line and a normally closed solenoid valve in its air vent line. Each of the redundant isolation sets of supply and vent solenoid valves is supplied from a separate 125V-dc power system and receives a separate signal from the engineered safety features actuation system.

The two valves in the isolation valve bypass lines are also closed by a signal from the engineered safety features actuation system to stop steam from escaping through these lines.

The main steam line isolation valves are capable of isolating the steam generators within five seconds of receiving the signal from the engineered safety features actuation system. In the event of a steam line break, this action should prevent continuous uncontrolled steam release from more than one steam generator. Protection is afforded for breaks inside or outside the containment even when it is assumed that there is a failure of one of the isolation valves.

Two redundant control signals are supplied by the engineered safety features actuation system to close the redundant isolation valve and the bypass line valves. The two valves in the bypass line for each pair of isolation valves are closed simultaneously with the isolation valves to stop steam from escaping through this line.

The loss of air supply at the valve operator should close the isolation valves and the bypass line valves.

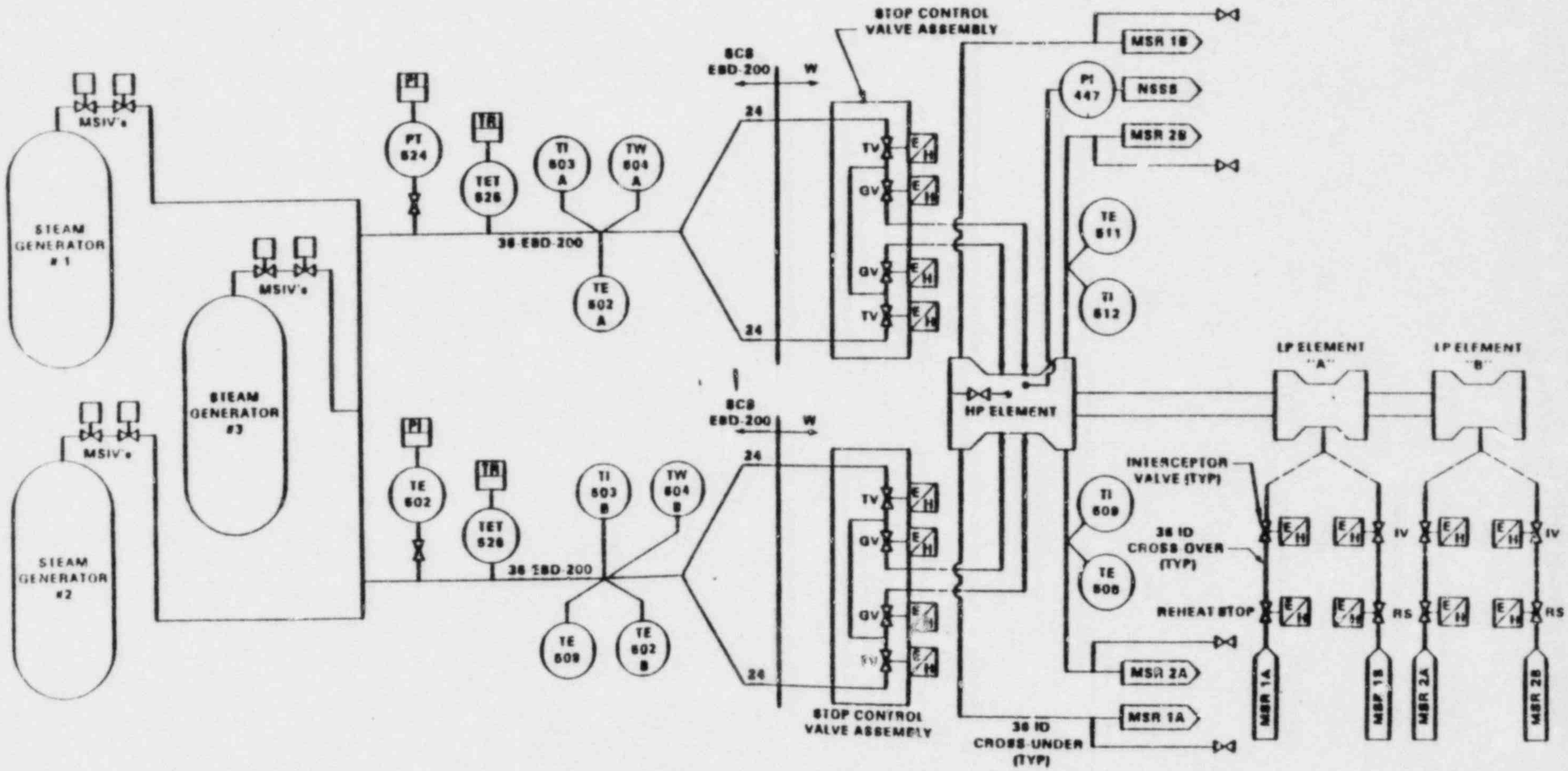

Figure 2-1 Turbine and Turbine Valve Arrangement

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+a,c

FIGURE 2-2. TURBINE AUTOSTOP AND ELECTROHYDRAULIC FLUID SYSTEMS.

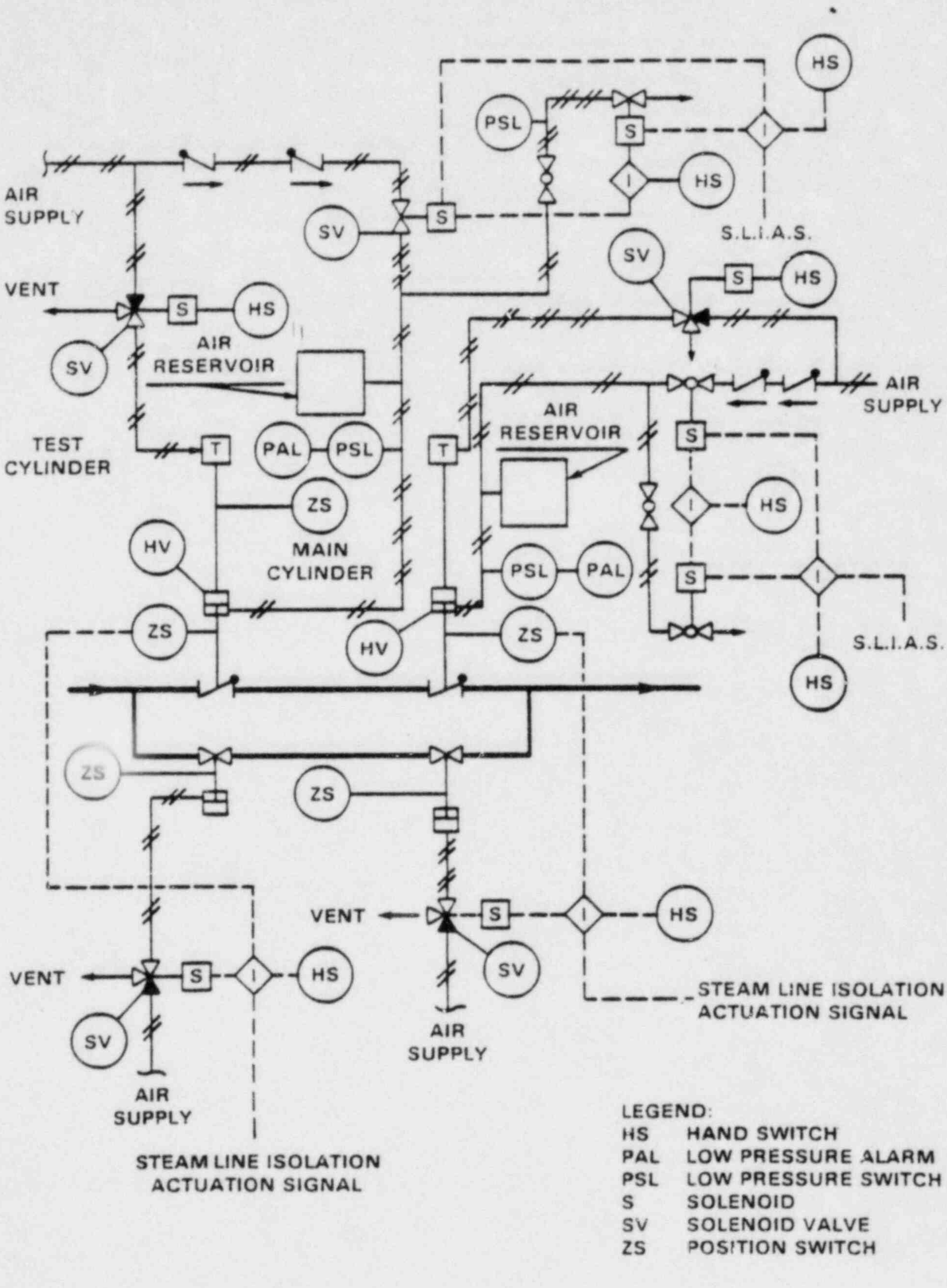


Figure 2-3 Main Steamline Isolation Valve

3.0 TESTING AND VALVE FAILURE MODES

Testing is conducted to verify that equipment is capable of performing its intended function. The turbine valves, as discussed in the previous section, function to control and protect the main turbine. To do so requires the valves to move freely and be capable of responding to control and protection signals. Valve testing ideally tests these abilities, or detects non-performance of these abilities. There are two degrees of performance or non-performance that testing may potentially demonstrate:

A. Equipment failure - the complete non-performance of equipment function.

B. Equipment failure precursors - identification of equipment conditions that will eventually lead to failure if not corrected.

A test which only identifies equipment failure is useful in limiting the time after failure that reliance is made on the faulty equipment. A test which identifies failure precursors impacts the time between and number of failures if the precursors are acted on. This section of the report addresses turbine valve testing and its implications on valve failure rate.

3.1 VALVE TESTING

Periodic testing of turbine valves consists of movement of each of the turbine valves through one cycle (from the valve position prior to testing, to full close, and returning to the original position). Typically, this test is conducted by the control room operator with an observer at the valve. Valve testing verifies freedom of movement of the valve stem and plug, the actuator rod and piston and verifies proper operation of either the servo valve or dump valve, depending on which valve is being tested, and the associated EH drain line (return line) to the EH reservoir. Testing verifies full closure of the turbine valves as testing is now constituted, i.e., nothing is inhibiting full closure. This type of testing is beneficial for, (1) detecting non or sluggish operation of the

valves, and (2) identification of gross outward appearance of valve condition.

In addition to periodic testing, periodic valve inspections are also performed. Valve inspections entail at a minimum, partial dismantling of the valve and valve housing to observe internal valve conditions. Valve inspections are the primary means of detecting distress or conditions that would lead to future valve failure. Valve inspections obviously require shutdown conditions and cannot be performed during operation.

3.2 SURROGATE VALVE TESTING

Periodic valve testing primarily demonstrates the ability of the valve to respond to a signal and close upon demand. Therefore, any operation of the valve which also demonstrates these abilities is a candidate for consideration as a surrogate test. The operation most similar to valve testing is that of a turbine trip. Tripping the turbine requires operation of portions of the autostop oil system, the EH fluid system and demonstrates valve closure. The only significant differences between a turbine trip and a typical test are the absence of an observer at the valves and the position of the governor valves. Westinghouse has determined that stationing an observer at the valves during turbine trip while shutting down qualfies as a surrogate valve test provided there has been no evidence of malperformance of governor valves during normal operation. Other evidence of proper valve operation is obtained from unobserved turbine trip if following trip the valves are verified to be closed.

3.3 VALVE FAILURE MODES AND IMPACT OF TESTING

The dominant failure modes that have been experienced for the valves of the type present at Farley Nuclear Station and that could cause valve failure are:

A. movement or loss of valve seat inserts

B. cracking or breaking of the muffler

C. seal ring - bonnet liner distress

D. misalignment of valve linkage.

These conditions are primarily internal to the valves and periodic testing would identify these conditions only to the extent that they are apparent to an observer or that they prevent valve operation. Data collected indicated these conditions have seldom been detected by testing unless a valve failure has resulted. In other words periodic testing most often identifies failures but not failure precursors. For example, a cracked muffler could potentially result in later muffler failure and subsequent internal valve binding, however, this "precursor" could not be detected during testing, only the subsequent failure of the valve could be detected.

For the above reasons, periodic valve testing does not have an impact on valve failure rate for these types of valves in that it has not readily identified failure precursors, only failures. Therefore increasing the periodic test interval will have no adverse impact on observed failure rates or valve lifetime. Testing that does not identify repairable defects cannot influence valve degradation and therefore valve failure rate. Westinghouse, after considering failure modes and testing methods, is confident that less frequent testing will not adversely impact turbine valve reliability.

4.0

FAILURE DATA AND ANALYSIS OF FAILURE PROBABILITY

Based on the data reviewed, less frequent valve testing does not appear to influence valve failure rate, it does theoretically impact the time interval after failure and before detection during which the valves would be incapable of performing the intended function. To determine the impact of this decrease in valve availability, a quantitative fault tree analysis of potential overspeed conditions was performed. This analysis considered the probability of:

1. Destructive overspeed/no turbine trip

2. Design overspeed - 120 percent overspeed

3. Intermediate overspeed - 130 percent overspeed.

Each of these conditions is uniquely different from the others due to the failures or successes that must occur for the condition to occur, hence necessitating consideration of all three. The ramificatons of each of these conditions is also very different. Each is addressed in this report section.

An integral part of performing a probability analysis is the use of appropriate data. In this case, the data relates to the observed failure rates and associated failure probabilities of the equipment constituting the valves and valve control systems. This section of the report details the data used in the fault tree analysis, it's sources and the statistical techniques used to calculate failure probabilities.

The final part of this report section describes a statistical test of the Westinghouse position that an increased test interval does not adversely impact valve failure rates. This study statistically evaluates failure rates for different test intervals obtained from plant data.

4.1 FAILURE DATA AND COMPONENT FAILURE PROBABILITIES

4.1.1 FAILURE DATA

The "Basic Event Service Experience" tabulation used to develop the March 1974 Westinghouse report titled "Analysis Of The Probability Of The Generation And Strike Of Missiles From A Nuclear Turbine" was updated with data obtained from the following Westinghouse sources.

A. Field Incidents Report - A hard copy sort, by month, of the incidents reported by Westinghouse Steam Turbine Generator Division (STGD) based on information received from District Offices and customer plant sites.

B. Outage Data System - A computerized data system that reports outage and availability data by unit or any group of units. The system also provides detailed lists of outages by unit, groups of units, time period, or other categories. The data is obtained weekly from District Offices, which contact utilities for the previous weeks information.

C. STGD Data Bank - A computerized generic file of turbines and their components where used reports and service histories can be produced for specific components. The data is obtained from internal records and from District Offices.

D. A panel of five knowledgeable engineers and engineering managers with an average of 25 years experience in turbine controls and valves.

E. 1982 survey of owners of operating Westinghouse nuclear turbines - a detailed questionnaire requesting valve testing operation and maintenance information was sent out.

F. Summary of a Westinghouse Generic Reliability Data Bank search - A summary report of valve related incidents in the Data Bank was reviewed by STGD for relevant valve and control system malfunctions.

The data for the service years contained in the tabulation of basic event service experience includes both fossil and nuclear unit experience. For all components except the steam valves the service application and environment is identical, therefore, combining these experiences is appropriate. At the time of the original issue of this tabulation, plug type valves of similar construction, whether used on fossil or nuclear units, formed the data base for the Throttle Valve, and Governor (Control) Valve events. At that time (1973) the preponderance of data were on fossil plug type valves. This experience is valid since the fossil valves experienced a duty and an environment which was more severe, or at minimum equally severe, as that of nuclear units. When the data were updated for this report, both fossil and nuclear valve data were included in the additional years of experience for Throttle Valves and Governor (Control) Valves. For Interceptor and Reheat Stop Valves only, the data base was changed to nuclear valves exclusively since the type of valves used with nuclear turbines are not of the same type used in fossil applications, and a reasonable amount of experience years has been accumulated on these nuclear Interceptor and Reheat Stop Valves. The resultant probability of failure based on this nuclear valve data is expected to be conservative since this valve type has an excellent service record but the service years are limited compared to those of other valves.

The data for the service (period years) was updated from the data referenced in the afore mentioned report for each of the basic events listed in Table 4.1-1. The updated data is provided in Table 4.1-2.

Events 1, 2, 12, 13, and 14 used [ ]^{a,c} years as a conservative estimate of the accumulated experience up to 1973 for these items. To this number, the additional experience for the units in service at the

end of 1972 and for the units placed in service from 1973 through 1981 was added. The new total became [ ]^{a,c} years.

Events 3, 4, 6, 7, 9, 10 and 23 have service experience equal to the number of unit years of units with EH control systems. This number was updated by adding to the original number the additional experience of those units that were in service at the end of 1972 and the experience of those units placed into sevice between 1973-1981. The new value becomes [ ]^{a,c}.

Events 5, 8, 22 and 24 were updated in a manner similar to the previous events. A factor of 3 times the unit years of experience was used because each turbine contains three identical or very similar devices.

Event 11 is based on sixteen times the number of EH unit years since each valve actuator contains a dump valve and there is an average of 16 actuators per turbine.

Events 16 and 19 were updated by adding to the previous number the additional valve years for the units making up the original number plus the valve years for units put into service between 1973-1981. The new number of [ ]^{a,c} valve years includes all fossil and nuclear plug type valve experience.

Events 17 and 18 are based on 8 times the EH unit years, because there is an average of 8 servo valves and servo valve circuits on each EH unit.

Event 20 is based on 17 times the number of EH unit years. Each of these units has one check valve per actuator for an average of 16 per unit plus one check valve between the ETF headers.

Event 21 is based on the number of EH unit years minus 9 units with EH control systems of a design that had a different speed detection circuit.

Event 25 is based on the experience of nuclear Interceptor Valves and Reheat Stop Valves that were put into service between 1969-1981. These two valves are identical in design.

The malfunctions shown in the Basic Event Service Experience tabulation are defined as follows.

Any failure of the component to perform its designated function when called upon to do so. These malfunctions are designated as relevant incidents. As applied to turbine steam inlet valves, relevant incidents or malfunctions are defined as failure of the valve to close on demand.

The number of malfunctions indicated considered all the sources identified in paragraphs A thru F above.

4.1.2 COMPONENT FAILURE PROBABILITIES

Every component was assigned to one of two failure classes -- failure on demand or time-related (standby) failure.

The calculations performed to obtain probabilities for these two failure classes involve somewhat different approaches and so will be discussed separately.

In many cases, the computation for a single component was done both ways for comparison with generic failure data, which vary in this choice. One selection was finally made for each component, however, as shown in the final column of Table 4.1-1.

4.1.2.1 Time-Related (Standby) Failure Calculations

For components assigned to this class, failures were assumed to occur at a constant rate, e.g., failures per million hours. The point estimate 50 percent and 95 percent upper confidence bounds (UCB) for these component failure rates were calculated using the equations:

$$\lambda = \frac{f}{T'}$$ Point Estimate

$$\lambda(0.5) = \frac{\chi^2(2f+2,0.50)}{2T'}$$ 50 percent

$$\lambda(0.95) = \frac{\chi^2(2f+2,0.05)}{2T'}$$ 95 percent UCB

Where:

f = Number of Observed Failures

T' = Operating Time

and the arguments of the χ^2 distribution are the number of degrees of freedom, taken as 2f+2, and the upper tail area of the distribution. The latter is given by (1-confidence level), since we here calculate a one-sided interval.

For all components, the historic operating time T' was taken to be 0.78 times the calendar service time T calculated from the date of commercial operation, i.e.:

$$T' = 0.78\ T$$

For a single component subject to failure at a constant rate λ and tested at intervals of θ time units, its unavailability A is given by:

$$\bar{A} = \frac{\lambda\theta}{2}$$

This is not the probability that the device is in a failed state at the time of testing, given by:

$$1-e^{-\lambda\theta} \cong \lambda\theta$$

but the average risk that the device will be inoperable when a demand arrives (the probability per unit time being assumed constant i.e., system separations are assumed to occur uniformly over the testing interval).

4.1.2.2 Failure on Demand Calculations

For components subject to failure on demand, the calculation is similar. Using p to distinguish the fact that the result is a probability we have:

$$\hat{p} = \frac{f}{MT} \qquad \text{Point Estimate}$$

$$p(0.5) = \frac{\chi^2(2f+2,0.50)}{2MT} \qquad \text{50 percent}$$

$$p(0.95) = \frac{\chi^2(2f+2,0.05)}{2MT} \qquad \text{95 percent UCB}$$

Where the denominator MT is the number of demands, calculated from the actual calendar year service time T and a value M for the annual number of demands. This value was conservatively derived by STGD using engineering judgement and experience.

The method by which the demand rate M was chosen is as follows:

The overspeed trip valve is tested monthly per Westinghouse's recommendation. In addition, every turbine trip opens this valve so that possibly a dozen more challenges per year may be incurred. The very conservative choice of M = 6/yr was chosen for this valve. All remaining components for which a demand failure probability was calculated were assumed to be tested annually for purposes of this report.

4.1.2.3 Selection Between High And Low Estimates Of Failure Experience

The failure rates calculated from STGD data utilized in every case only the known failure occurrences. In some cases, for this report much higher incidence rates were conservatively assigned by STGD to account for unreported failures. These were in most cases comparable in magnitude to the 95 percent upper bounds applied to known failures, so that in the end, they were discarded as less amenable to verification, i.e., less reproducible or scrutable. (They were, however, considered in verifying the data.)

A particularly useful comparison was made of failure rates for similar components. In some cases, the selection was made of a higher failure rate experienced in the similar component, where the degree of physical similarity and commonality in operating environment could be established.

4.1.2.4 Generic Data Search

For every component an attempt was made to compare STGD's failure experience with failure information from generic data sources. The mainstay of this work was nuclear utility operating experience, as documented in the Westinghouse Generic Reliability Data Source which includes data from the Nuclear Plant Reliability Data System, the NRC Licensee Event Reporting System, the NRC Gray Book Reports and data collected independently by Westinghouse.

No attempt was made to adjust the data for trends in service time. This is conservative since "infant failures" decrease with time.

In addition to the computer data base, a number of reports and other compilations were used frequently. These included in particular IEEE-500, WASH-1400, the series of NUREG reports reflecting LER reports, and proprietary failure data compilations previously made by Westinghouse.

After a thorough review of STGD and generic data, a failure rate selection was made. After discussion with STGD engineers, apparent differences between Westinghouse and generic failure data were in every case resolved in favor of the Westinghouse data, which is obviously of maximum relevance, and which in every case showed adequate statistical precision. Higher failure data from generic sources were examined with special attention before the STGD experience was adopted.

TABLE 4.1-1

BASIC FAULT TREE EVENT FAILURE MODES

BASIC EVENT	DEVICE	FAILURE MODE	FAILURE TYPE
1.	Mechanical Trip Mechanism	FTO	D
2.	Auto Stop Oil Cup Valve	FTO	D
3.	20/AST Solenoid	FTO	D
4.	20/AST Actuation Train	FTO	D
5.	Speed Detector	Fails Low	D
6.	Interface Valve	FTO	D
7.	Interface ETF Drain	Clogged	S
8.	20/ET Solenoid	FTO	D
9.	Pressure Switch	FTO	S
10.	Primary ETF Drain	Clogged	S
11.	Dump Valve	FTO	S
12.	ETF Drain to Trip Block	Clogged	S
13.	Auto Stop Oil	Clogged	S
14.	Dump Valve Drain	Clogged	S
15.	Not Applicable		
16.	Throttle Valve	FTC	S
17.	Servo Valve	FTO	S
18.	Servo Valve Circuitry	Failed	S
19.	Governor Valve	FTC	S
20.	Check Valve	FTO	D
21.	Loss of Load Detection	Failed	S
22.	OPC or ET Speed Detection	Fails Low	S
23.	OPC Actuation Train	Failed	S
24.	20/OPC Solenoid	FTO	D
25.	Reheat Stop/Interceptor Valve	FTC	S

FTC - Fails to Close

FTO - Fails to Operate - 1, 2, 3, 4, 8, 9, 11, 17, 24

FTO - Fails to Open - 6, 20

S - Standby Failure

D - Failure on Demand

TABLE 4.1-2

BASIC EVENT SERVICE EXPERIENCE

Event Number	Service = n	Malfunctions
1		a,c
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		

4.2 FAULT TREE ANALYSIS

This section discusses the fault tree analysis that was performed to estimate the probability of turbine overspeed and to determine the sensitivity of this event to changes in the valve test frequency. The following subsections discuss tree construction and quantification. Results and conclusions are also presented.

4.2.1 FAULT TREE CONSTRUCTION

Fault trees were constructed for three turbine overspeed conditions: design overspeed, destructive overspeed, and intermediate (130 percent) overspeed. These top events and the system failures associated with them are defined in Section 2.4 of this report.

The fault trees, presented as Figures 4-1 through 4-3, were developed in accordance with the system failure logic. For example, design overspeed occurs when the overspeed protection system fails at 103 percent overspeed, but the emergency trip system succeeds at 111 percent overspeed. Consequently, the design overspeed tree requires that one or more governor valve or interceptor valve remains open so that a steam path exists to either a high or low pressure turbine.

The Westinghouse GRAFTER code was used to edit and maintain the fault trees on file. Basic events were established that reflect the level of detail determined to be appropriate for this study. These basic events, listed in Table 4.2-1, largely correspond to those developed in the 1974 Westinghouse study previously mentioned. It is these events for which failure probability estimates have been calculated as the initial step in the quantification process.

4.2.2 FAULT TREE QUANTIFICATION

Table 4.2-2 lists the input probabilities calculated for each basic event. The statistical methods used in deriving these values are

explained in Section 4.1 The values in the Case A column of Table 4.2-2 were obtained using 95 percent confidence limits, while the the Case B values represent a 50 percent level of confidence.

Certain basic event probabilities depend on valve testing interval assumptions, that is, these elements are involved in the test procedure, and their input probabilities will be reduced if testing is done more frequently. These basic events are listed in Table 4.2-3. Events 16 through 19 are dependent only on governor and throttle valve testing; events 11, 14, and 25 are dependent only on interceptor and reheat stop valve testing.

Three testing intervals were examined in this study: yearly, monthly, and weekly testing. Sensitivity runs were made for both the 50 percent and 95 percent confidence values. Each fault tree was therefore quantified six times, with the following case designations:

A1 - 95 percent confidence values, yearly testing
A2 - 95 percent confidence values, monthly testing
A3 - 95 percent confidence values, weekly testing
B1 - 50 percent confidence values, yearly testing
B2 - 50 percent confidence values, monthly testing
B3 - 50 percent confidence values, weekly testing

System separation with sufficient steam supply is a precondition for any overspeed event. This is represented in the fault trees by an "and" gate under the top event, and the trees have been quantified with the assumption of three separations per year. Also implicit in the quantification is the assumption that, for design and intermediate overspeed, the emergency trip system stops all steam flow to the high pressure turbine. This latter assumption is treated in these trees as an undeveloped event with probability one.

Quantifications were performed using the WAMCUT computer code, and results are presented in Tables 4.2-4 through 4.2-6.

4.2.3 EVALUATION OF RESULTS

In addition to top event probabilities, Tables 4.2-4 through 4.2-6 list the dominant basic events for each case. This information, determined through examination of the fault tree cutsets, is meaningful in that it identified the major contributors to turbine overspeed probability, and provides physical explanation of the demonstrated degrees of sensitivity. Results for each overspeed condition are discussed below.

4.2.3.1 Design Overspeed

The probability of design overspeed is conservatively estimated by the fault tree analysis performed for this study to be no greater than 3.8 x 10^{-2} per year. This value is taken from Table 4.2-4, Case A1, in which 95 percent confidence values are used, an annual testing interval is assumed and system seperation (initiating event) that does not result in immediate turbine trip is assummed to occur 3 times per year. This latter assumption is extremely conservative for the Farley plant. As discussed in section 2.0 a system seperation at Farley results in a turbine trip. Not having the turbine tripped at the onset of an overspeed condition is necessary for design overspeed to occur. Nevertheless, for purposes of evaluating the sensitivity of design overspeed probability to valve testing frequency, this feature may be ignored. It will be considered however in discussions of missile generation probability.

As shown in the table, design overspeed is relatively insensitive to valve testing interval. If monthly rather than yearly testing is assumed, the top event probability is reduced by less than a factor of 3. Furthermore, increasing the testing frequency from once per month to once per week - Cases A2 to A3, and B2 to B3 -- has virtually no effect on the top event value.

The reason for this insensitivity is that the basic events that contribute most to the design overspeed probability, [

]^{a,c}, are not involved

in the valve test procedure. Failure of [

]^{a,c} is a tertiary contributor to design overspeed. This event is sensitive to valve testing and is the source of the approximately [

]^{a,c} reduction in top event probability from yearly to monthly testing.

4.2.3.2 Intermediate Overspeed

As shown in Table 4.2-5, the probability of intermediate (130 percent) overspeed is conservatively estimated to be no greater than 6.8 x 10^{-5} per year, assuming annual valve testing and using 95 percent confidence values. A more realistic estimate, based on 50 percent confidence values, provides a probability of 7.2 x 10^{-6} per year.

Also shown in the table is the sensitivity of the top event to changes in testing frequency. Intermediate overspeed demonstrates significant sensitivity -- approximately a factor of 20 -- if yearly and monthly cases are compared. The monthly to weekly sensitivity, however, is little more than a factor of 2. This phenomenon is due to the presence, in the yearly testing cases (A1 and B1), of dominant cutsets involving [

].^{a,c} The magnitude of these cutsets is reduced in going from yearly to monthly testing. The reduction in relative importance of these cutsets also explains why further decreasing the testing interval from monthly to weekly testing has relatively minor impact.

4.2.3.3 Destructive Overspeed

The probability of destructive overspeed, listed in Table 4.2-6, is conservatively estimated (Case A1) to be no greater than 6.7 x 10^{-6} per year, and a more realistic estimate (Case B1) can be taken as approximately 2.2 x 10^{-6} per year.

Destructive overspeed, similar to intermediate overspeed, exhibits significant sensitivity if one considers yearly versus monthly testing. Again, the sources of this sensitivity are dominant cutsets involving

two elements -- ie. [
]^{a,c} -- both of which are involved in the valve test procedure. These sensitive cutsets are greatly reduced in relative importance for the monthly cases (A2 and B2). Consequently, little effect is observed, with respect to top event probability, when the testing interval is further reduced from one month to one week.

4.2.3.4 Summary

In summary, it has been shown that design overspeed demonstrates relative insensitivity to valve test frequency. Intermediate and destructive overspeed, conversely, do exhibit significant sensitivity to changes in testing frequency. However, it should be noted that the probability estimates for these events are consistent with guidelines established in Regulatory Guide 1.115, "Protection Against Low Trajectory Turbine Missiles".

The relationship of overspeed probability to missile generation, and the contribution of fault tree analysis to the conclusions of this study are discussed in subsequent sections of this report.

TABLE 4.2-1

FAULT TREE BASIC EVENTS

EVENT NUMBER	EVENT DESCRIPTION
1	Mechanical Trip Mechanism failure
2	Auto Stop Oil Cup Valve failure
3	20/AST Solenoid failure
4	20/AST Actuation Train failure
5	Speed Detector failure
6	Interface Valve failure
7	Interface ETF Drain clogged
8	20/ET Solenoid failure
9	Pressure Switch failure
10	Primary ETF Drain clogged
11	Dump Valve stuck closed
12	ETF Drain into Trip Block clogged
13	Auto Stop Oil clogged
14	Dump Valve Drain clogged
15	Not applicable to study
16	Throttle Valve stuck open
17	Servo Valve failure
18	Servo Valve Circuitry failure
19	Governor Valve stuck open
20	Check Valve failure
21	Loss of Load Detection failure
22	OPC or ET Speed Detection failure
23	OPC Actuation Train failure
24	20/OPC Solenoid Pair failure
25	Reheat Stop/Interceptor Valve stuck open

TABLE 4.2-2

BASIC EVENT INPUT PROBABILITIES

a,c

EVENT	CASE A (95 PERCENT)	(CASE B (50 PERCENT)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		

TABLE 4.2-3

INPUT PROBABILITIES FOR BASIC EVENTS SENSITIVE TO
VALVE TESTING INTERVAL ASSUMPTIONS

	CASE A (95 PERCENT)	(CASE B (50 PERCENT)
EVENT 11		
1) Yearly Testing		
2) Monthly Testing		
3) Weekly Testing		
EVENT 14		
1) Yearly Testing		
2) Monthly Testing		
3) Weekly Testing		
EVENT 17		
1) Yearly Testing		
2) Monthly Testing		
3) Weekly Testing		
EVENT 18		
1) Yearly Testing		
2) Monthly Testing		
3) Weekly Testing		
EVENTS 16 AND 19		
1) Yearly Testing		
2) Monthly Testing		
3) Weekly Testing		
EVENT 25		
1) Yearly Testing		
2) Monthly Testing		
3) Weekly Testing		

a,c

TABLE 4.2-4

DESIGN OVERSPEED PROBABILITIES

CASE	PROBABILITY	DOMINANT BASIC EVENTS
A1	3.8E-2	a,c
A2	1.6E-2	
A3	1.4E-2	
B1	1.2E-2	
B2	4.8E-3	
B3	4.3E-3	

TABLE 4.2-5

INTERMEDIATE (130 PERCENT) OVERSPEED PROBABILITIES

CASE	PROBABILITY	DOMINANT BASIC EVENTS
A1	6.9E-5	a,c
A2	3.4E-6	
A3	1.5E-6	
B1	7.2E-6	
B2	5.5E-7	
B3	2.9E-7	

TABLE 4.2-6

DESTRUCTIVE OVERSPEED PROBABILITIES

CASE	PROBABILITY	DOMINANT BASIC EVENTS
A1	6.7E-6	[ ]a,c
A2	3.5E-7	
A3	1.4E-7	
B1	2.2E-6	
B2	8.3E-8	
B3	[illegible].1E-8	

4.3 STATISTICAL EVALUATION OF TESTING INTERVAL AND VALVE FAILURE

The data can be represented as follows:

Testing Schedule	Exposure (valve-hours)	Failures
Weekly	[	]^{a,c}
Monthly		
Every 2 weeks		
Not regular		

These data invite the computation of failure rates (number of failures per valve-hour) for each testing schedule followed by appropriate comparisons. The question of whether the calculated rates are sufficiently different to constitute evidence of real differences among schedules naturally arises. This section discusses this question and related issues.

The working assumption for this discussion is that within any testing schedule, failures occur randomly over time at a constant rate which is characteristic of the particular schedule. This is a very natural assumption that is used frequently in dealing with data involving the occurrence of a more or less rare event over time. Based on this assumption, the number of failures in exposure-time t while using a given testing schedule has a Poisson distribution with parameter $\mu = \lambda t$. The quantity λ is the failure rate mentioned above and assumed constant within any testing schedule. Using the weekly schedule as an example, there was [ ]^{a,c} valve-hours.
Denoting parameter estimates as $\hat{\mu}$ and $\hat{\lambda}$ we have

[ ]^{a,c} failures per valve-hour.

Once an estimate for λ, i.e. $\hat{\lambda}$, is available, one can estimate the parameter of the Poisson distribution that would govern the number of failures under a weekly testing schedule for any number of valve-hours

of exposure. For example, the number of failures in [ ]^{a,c} valve-hours would be estimated to have a Poisson distribution with parameter [ ].^{a,c} Notice that the monthly schedule had an exposure of about [ ]^{b,c} was observed. Does this mean that the monthly schedule involves a lower failure rate than the weekly, or does the variability inherent in the Poisson distribution readily explain this discrepancy ? This exemplifies the kind of question to be dealt with in the remainder of this section.

One way to summarize the information about the underlying failure rate (λ) contained in a given set of data is to compute a confidence interval for this unknown parameter. Using classical methods one can state that if 1-failure has been observed then a 95 percent confidence interval for the Poisson parameter μ is

$$0.25 \leq \mu \leq 5.57$$

Since $\mu = \lambda t$ this means that

$$0.25/t \leq \lambda \leq 5.57/t$$

with 95 percent confidence. For the weekly data then, since [ ],^{a,c} we find

[ ]^{a,c} (weekly)

while for the monthly data [ ]^{b,c} we find

[ ]^{a,c} (monthly).

These intervals convey what we know about the values of λ under the two schedules in a way that reveals the uncertainty involved. Each interval gives the values of λ that are reasonably consistent with the corresponding set of data. The chosen confidence coefficient of 95 percent sets the standard for what is to be regarded as "reasonable". For given

data, increasing the coefficient merely enlarges the interval.

The confidence intervals for the failure rates under weekly and monthly testing have a considerable overlap. This says that the difference between the observed rates [ ]^{a,c} could easily arise from chance alone in the absence of any real difference. While the two confidence intervals are of interest in themselves as a summary of what the data say about the individual failure rates, a more direct approach for the comparison of the two failure rates is available. Under the Poisson assumptions, it is possible to calculate a confidence interval for their ratio. The ratio of the weekly to the monthly failure rate may be estimated from the data to be [ ]^{a,c} and the 95 percent confidence interval is

[ ]^{a,c} (weekly/monthly).

For the failure rates to be judged different on the present data, this interval would have to exclude the value 1. This shows once again that even though the observed rates are different [ ]^{a,c} such a result is quite consistent with the true rates being equal ($\rho = 1$). Of course, the confidence interval is quite broad. This means that the amount of data is not sufficient to give a very precise comparison of the two rates. Ironically, the precision would improve if there were more failures. On the other hand, a greater exposure would not help the precision of the comparison. Greater exposure would, however, help the precision of the estimates of the individual rates. This points to the importance of considering the magnitudes of the individual rates as well as their comparison. If they are both quite small, it is not possible to make a precise comparison; correspondingly, in such a case it probably does not matter which rate is larger.

The data for the other testing schedules do not add much to the above analysis. The every-other-week schedule is based on only one unit and hence does not have a sufficiently broad base to be analyzed by itself

while the non-regular testing regimen suffers from the data-paucity syndrome mentioned above [ ].[a,c] For completeness we will combine the first three data sets into one which represents the practice of regular testing and compare this with the remaining set which represents the absence of a regular testing schedule. The data may then be represented as

Regular Testing	Exposure (valve-hours)	Failures
Yes	[	][a,c]
No		

The 95 percent confidence intervals for the individual failure rates are:

[ ][a,c] (regular)

(not regular)

Again there is considerable overlap between these intervals, and therefore the data fail to reject the propositon that the two testing regimens have the same underlying failure rates. The 95 percent confidence interval for the ratio of the two failure rates is

[ ][a,c] (regular/not regular)

With an estimated value of $\hat{\rho} = 1.12$. The interval does not exclude the value 1 and therefore provides no basis for concluding that the underlying rates are different.

The overall failure rate estimate based on all the data (that is, assuming there is no dependence of failure rate on testing regimen) is [ ][a,c] failures per million valve-hours. The 95 percent confidence interval for this overall λ is

[ ][a,c] (overall)

Based on this analysis we conclude that these data give no evidence of a dependence of failure rate on testing interval. Moreover, under the assumption of a single failure rate these data would put that rate at between [ ].[a,c]

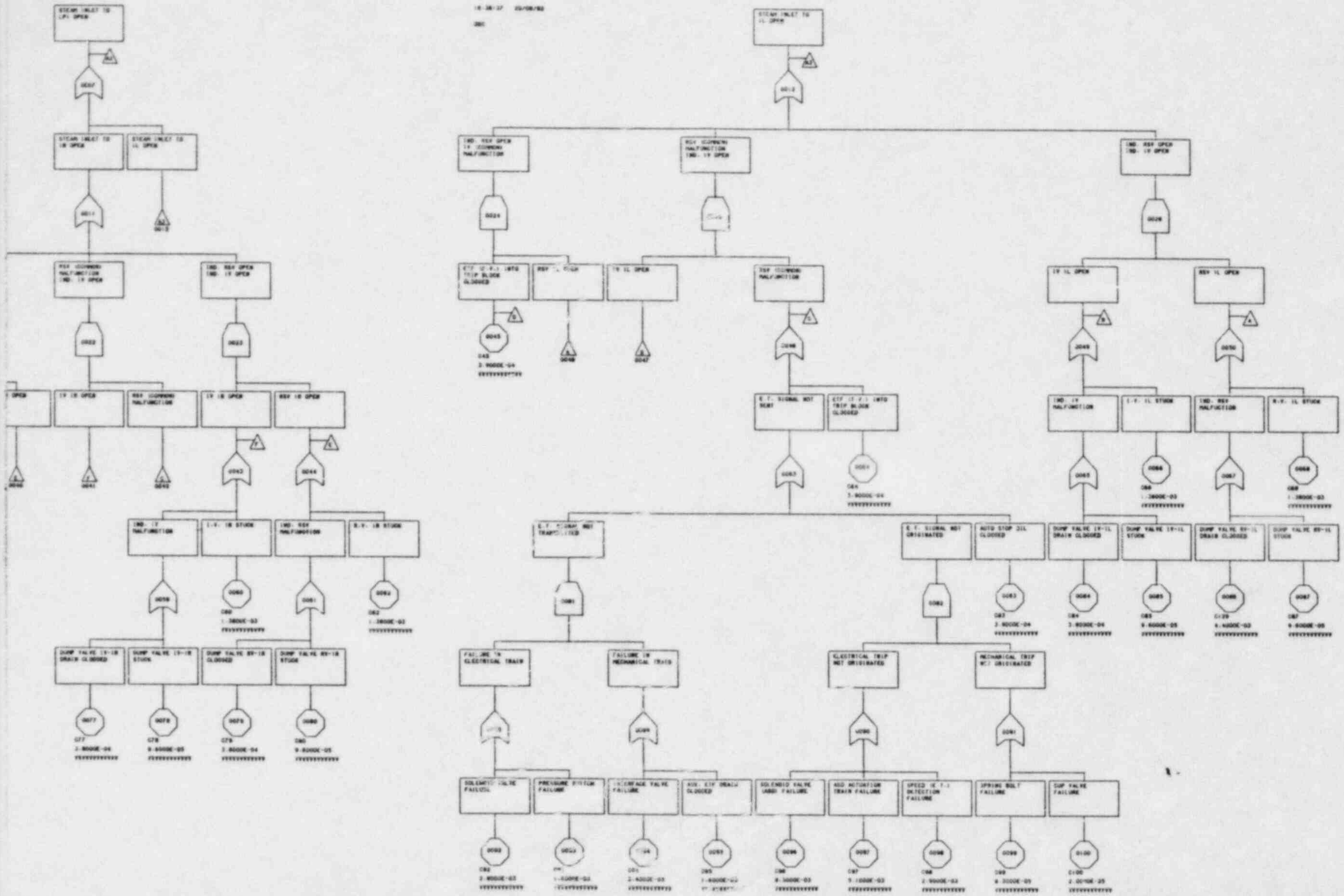
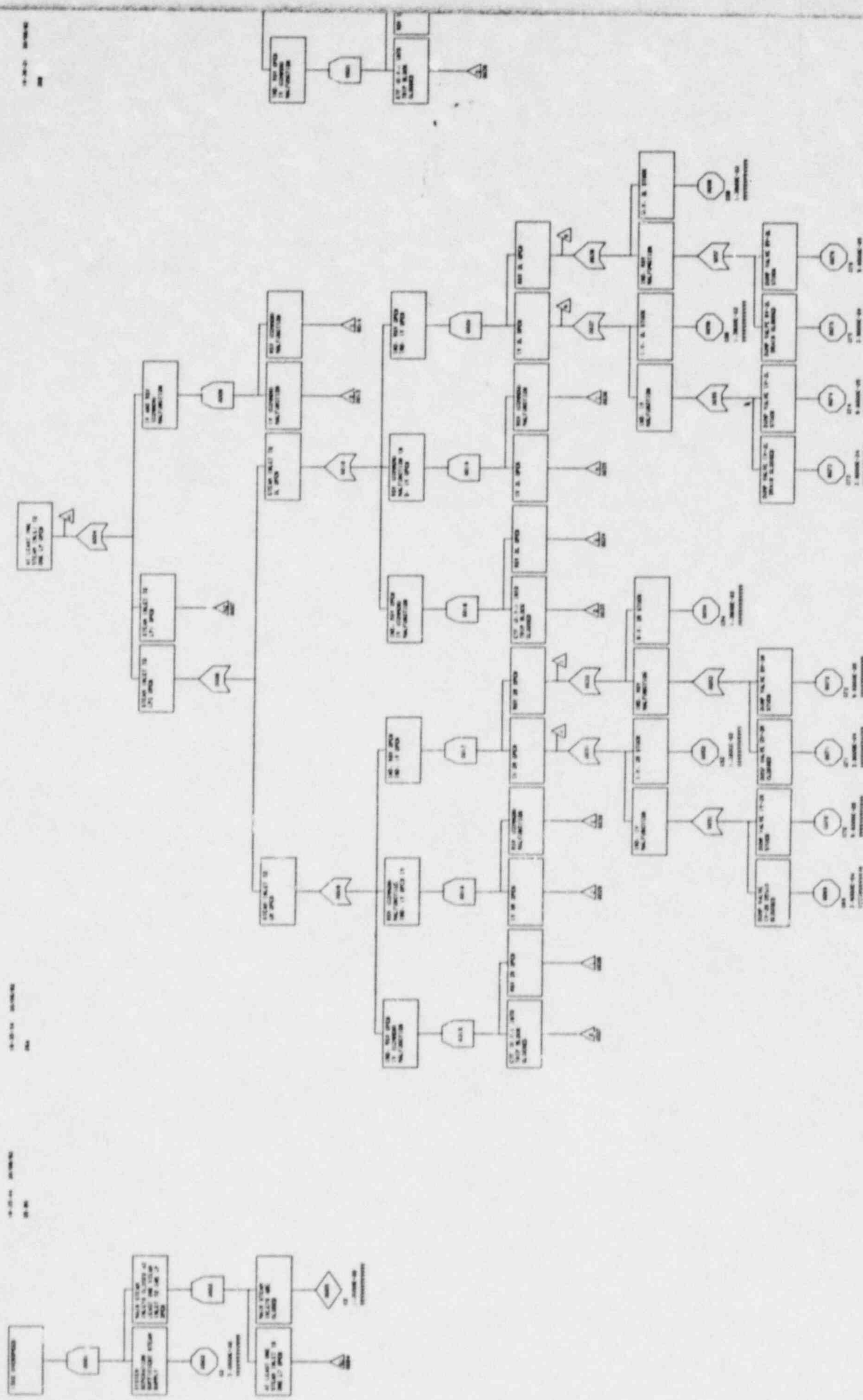


Figure 4-3. Intermediate (130%) Overspeed Fault Tree



5.0 SAFETY ANALYSIS AND MISSILE GENERATION PROBABILITY

The previous section statistically demonstrated the high reliability of the turbine trip system assuming yearly testing. This section of the report will demonstrate the importance of incorrect or non-operation of the turbine trip system to turbine missile generation probability and core safety limits. First, the probability of the various overspeed events will be linked to potential missile generation. Second, the effect of not tripping the turbine following a transient will be discussed in terms of the accident analysis. This discussion will demonstrate the acceptability of no turbine trip in terms of analysis results and/or MSIV operation terminating steam to the turbine.

5.1 MISSILE GENERATION PROBABILITY

This section evaluates the potential for missile generation assuming a turbine overspeed has occurred. Such an assessment requires consideration not only of the likelihood of turbine overspeed, but also of the conditional probability of missile generation. The entire analytical operation can be conveniently expressed in the form of the following equation:

$$P = P_1 P_2$$

P_1 represents the estimated probability of turbine overspeed, P_2 represents the conditional probability of missile generation and P represents the absolute probability that a turbine missile will be generated.

5.1.1 TURBINE OVERSPEED PROBABILITIES

Turbine overspeed probabilities for the intermediate and destructive overspeed cases are taken from the fault tree analysis results presented in Section 4.2. From Tables 4.2-4 through 4.2-6, the following conservative estimates, assuming 95 percent confidence, 3 separations a year and a yearly test interval are obtained:

Destructive Overspeed: P_1 = 6.7E-6/year

Intermediate (130 percent) Overspeed: P_1 = 6.9E-5/year

These values are used in this section to provide an upper bound estimate of turbine missile generation risk. A more realistic estimate could be obtained by selecting more representative cases (B1, for example) from the tables in Section 4.2.

Design overspeed probability was calculated to be 3.8×10^{-2} using the fault tree analysis described in section 4.2, assuming very conservatively, that each year 3 system seperations occur that do not result in immediate turbine trip. As discussed previously, a precondition of design overspeed is a system seperation that is not accompanied by a turbine trip at event onset. Also discussed previously was the fact that at Farley, a turbine trip will occur at the onset of any overspeed event caused by a loss of load due to electrical fault, given proper operation of protective features. Design overspeed probability then, is the product of the probability of design overspeed and the probability of failure of the electrical fault to cause a turbine trip. An exact value for this latter probability was not available for this report, however generic data sources indicate that an appropriate value would be 1×10^{-4}. Making allowances for the uncertainty associated with this value and conservatively using 1.0×10^{-3} results in a design overspeed probability of 3.8×10^{-5} using this approach .

A second method of calculating the probability of design overspeed that has been used, relied on operating experience. Based on operating experience Westinghouse has estimated the probability of design overspeed to be 3.2×10^{-3} per demand using a 95 percent upper confidence bound. This estimate was used in preparing previously submitted turbine missile reports for the Farley turbine. This calculated probability value is believed to be conservative since Westinghouse is not aware of any occurrence of a design overspeed event in a Westinghouse nuclear turbine which was caused by failure of turbine inlet valves or the control system.

5.1.2 TURBINE MISSILE GENERATION

Given the likelihood of turbine overspeed, one next needs to determine the conditional probability of generating a turbine missile. In this study, it has been conservatively assumed that a destructive overspeed event will always result in missile generation. Thus, in terms of the above equation, $P_2 = 1$ for the destructive overspeed case. The contribution to total missile generation probability from destructive overspeed is then $P_1 \times P_2$, which equals 6.7×10^{-6} per year.

No detailed analysis has been performed to determine the conditional probability of missile generation for the intermediate (130 percent) overspeed case. It is believed, however, that this conditional probability will be at least one order of magnitude lower than the conditional probability of generating a missile at destructive overspeed. The contribution to total missile generation probability from intermediate overspeed will thus be no greater than that from destructive overspeed, and both values are exceedingly small in both relative and absolute terms.

Design overspeed missile generation probabilities have been calculated for the Farley Turbine using a design overspeed probability of 3.2×10^{-3} as discussed above and considering LP disc inspection interval. The results of the most recent of those studies are provided below. The values presented are for missile generation, ie. $P_1 \times P_2$.

Inspection Interval (*)	Probability of Missile Generation Due to Disc Rupture
1	
2	
3	
4	
5	

a,c

(*) The units are operating years (as opposed to calender years)

Missile generation probability can also be calculated using the value obtained from the design overspeed fault tree. Assigning a P_2 value of [

]^{a,c} results in a missile generation probability of [ ]^{a,c}.

5.1.3 CONCLUSIONS

On the basis of information presented in the preceding sections, the likelihood of missile generation due to overspeed is acceptably low even considering yearly valve testing, and in the case of design overspeed, is relatively independent of valve test frequency. Thus, the probability of missile generation will not exceed an acceptable limit even if testing is performed no more frequently than yearly.

5.2 NON-LOCA ANALYSIS

The FSAR analyses assume the turbine trips on a reactor trip to mitigate an excess cooldown following the transients and the accidents. The effect of the turbine failure is a continuous cooldown of secondary and primary sides. Taking credit for the closing of the turbine stop valves in the SAR analyses can be justified on the basis of:

A. the throttle and governor valves are in a series parallel arrangement and closure of either the throttle or the governor valves will terminate steam flow to the turbine.

B. the valves fail closed on loss of electrical power or hydraulic pressure.

To determine the consequences of reactor trip without the turbine trip, various typical transients and accidents have been analyzed with different failures. The results show that the continuous cooldown for those transients (with a return to power) will be bounded by the double ended steamline break (DESLB) presented in the FSAR which meets the

safety criteria. Further, the consequences of the accidents like steamline break without the turbine trip are bounded by other generic studies. These results indicate that there are no additional safety concerns other than those discussed in the SAR.

5.2.1 METHOD OF ANALYSIS

The review of the safety analyses demonstrate the minimum DNBR for most transients occurred immediately prior to scramming the rods. Following the reactor trip, if the turbine fails to trip, there will be a cooldown caused by the turbine continuing to draw steam in the absence of a significant heat source. This essentially means that the original transient has been transformed into a steamline break. Hence, this new transient has two phases, (a) the first phase identical to the initiating transient until reactor trip and (b) a cooldown phase similar to an at-power steamline break transient after the trip. Hence, to study the consequences of this new transient, four different conditions (Figure 5-1) have been identified to investigate the change in the severity of the transient with different failures. These conditions are listed in the order of increasing conservatism and decreasing probability of occurrence.

CASE A - After an initiating transient, the turbine trips -- Standard FSAR analysis with conservative assumptions.

CASE B - An initiating transient and the turbine fails to trip, with other conservative FSAR analyses.

If the related components in the steamline break protection system close the main steam isolation valves (MSIV), the transient is essentially terminated. For this case, it will be shown the shutdown margin is more than the negative reactivity insertion due to cooldown and the reactor will remain subcritical. As Farley Units have two MSIV's on each main steamline, all the transients and accidents will be bounded by this

condition. However, to demonstrate the inherent safety, an additional, unmechanistic failure of a MSIV pair will be considered in CASE C.

CASE C - Initiating transient; turbine fails to trip; a non-isolated steam generator due to unmechanistic failure of a MSIV pair, no stuck rod. For these cases, it is shown that due to the additional trip reactivity of the control rod, the cooldown phase will become inconsequential as demonstrated in the Westinghouse topical, "Reactor Core Response to Excessive Secondary Steam Releases", WCAP-9226. However, to extend this study, the condition with the most reactive RCCA stuck in its fully withdrawn position is considered in CASE D.

CASE D - Initiating transient; turbine fails to trip; a non-isolated steam generator due to unmechanistic failure of a MSIV pair and the most reactive RCCA stuck in its fully withdrawn position. If this stuck rod assumption is made in conjunction with a failed MSIV pair, the reactor becomes critical during the second phase (cooldown). Since this phase of the transient transforms into a steamline break accident, the time at which the cooldown begins can be considered to be the start of the steamline break accident. Hence, the return to power, RCS pressure and RV inlet temperatures after the trip can be compared with those of steamline break accident presented in the FSAR.

To analyze these conditions, the FSAR transient can be easily modeled to include the cooldown phase. To investigate the effects of various plant conditions that may affect the severity of the cooldown at the time of trip, the following transients were selected:

a) Rod Withdrawal at Power - typical of transients with higher RCS pressure and power at the time of trip,

b) Partial Loss of Flow - typical of transients with loop effects and reduced RCS flow at the time of trip,

c) RCS Depressurization - typical of transients with decreased RCS pressure at the time of trip.

The LOFTRAN code is used to study the new transient. The modeling of the steam flow for the non-isolated loop is: (1) equal to the initial flow, (2) the flow coincides with critical flow through the 1.4 square feet flow restrictor and (3) follows the obvious pressure dependent critical flow through the flow restrictor. This conservative model maximizes the cooldown effect and increases the moderator feedback. To maximize the cooldown, the SAP transients were considered using the conservative reactivity assumptions used for standard steamline break analysis. As a future conservatism, no credit was taken for the boron in the boron injection tank (BIT).

5.2.2 CASE A

It has been shown in the FSAR analyses that by taking credit for the operation of safety grade equipment and the turbine trip on reactor trip, the consequences are shown to be acceptable. The core heat flux, RCS pressure and RV inlet temperature changes with time for a typical transient are shown in Figures 5-2 a, b and c. Only the responses in the second phase are of interest and it can be seen that the core heat flux reduced substantially after the trip and the reactor did not return to power.

5.2.3 CASE B

For any transient that employs the turbine trip following the reactor trip, the sequence of events which will occur should the turbine fail to trip, would look identical to the FSAR analysis until the time at which the reactor trip is generated. Steam will then continue to flow equally from all three steam generators cooling the secondary and primary sides until the MSIV's close in response to the low steamline pressure signal. Closure of MSIV's effectively terminates these transients such that no further reactivity insertion due to cooldown will occur and the plant can be brought to cold shutdown similar to a case with a turbine trip. MSIV closure due to low steamline pressure is lead-lag compensated and hence the valves close before the actual setpoint is reached. The minimum possible temperature the primary side can reach will be higher than the saturation temperature of the secondary side at the pressure corresponding to the MSIV isolation pressure. As an upper bound, the reactivity insertion corresponding to this minimum secondary side temperature relative to hot, no load conditions for typical cases are:

a) Rod Withdrawal at Power = .85 percent Δk

b) Depressurization = 1.43 percent Δk

c) Partial Loss of Flow = 1.75 percent Δk

These positive reactivity insertions are less than the minimum shutdown margin of 1.77 percent Δk at hot no load, and hence the reactor will stay subcritical up to the time of MSIV closure and the plant can be brought to cold shutdown following the emergency procedures. The consequences will be the same as that presented in the FSAR analyses. The core heat flux, RCS pressure and RV inlet temperature changes with time for RWAP transient are shown in Figure 5-3 a, b and c. Heat flux responses to the cooldown can be seen from time of trip until the MSIV's close. The reactor remains subcritical after the trip.

5.2.4 CASE C

Failure of turbine trip following a reactor trip with an unmechanistic failure of a MSIV pair, can also be analysed and the sequence of events are as follows. This is done to further demonstrate the inherent conservacism of these calculations. As in the previous case, the steam will continue to flow equally from all three steam generators cooling the primary and the secondary sides until the MSIV's close in response to the steamline pressure signal. However, in this case, only two out of three steam generators are isolated. Assuming this unlikely event, the steam will continue to flow from the faulted steam generator and cause the NSSS to stabilize at some power level corresponding to the flow from the faulted steam generator until the time is reached at which that steam generator dries out. At that point, steam-flow will decrease to the flow of the auxiliary feedwater system, NSSS load will drop, and NSSS power level will decrease markedly. Also during this time, boric acid is being added to the RCS helping shutdown the core. A typical rod withdrawal at power transient has been analysed with the unmechanistic failure of a MSIV pair (two MSIV's in one steam line) but without a stuck rod. The results are presented in the Figures 5-4 a, b and c. It is shown that the reactor remains subcritical and the consequences are no more severe than in the FSAR analyses.

5.2.5 CASE D

We can consider hypothetically all the above failures combined with a stuck rod. This transient will be more adverse due to more restrictive shutdown margin and reactivity coefficients. Due to the continuous cooldown, the core will become critical and will return to power. Topical report (WCAP-9226) has shown that the steamline break analyses from hot shutdown represents the worst case. Postulated steamline breaks occurring from significant power levels are bounded by the same break size from hot shutdown due to the advantage of greater stored energy and reduced steam generator inventory. If no turbine trip occurs following a reactor trip, any transient in the FSAR can be considered as a cool down accident following a plant trip similar to at power

steamline break transients. The results of a typical analysis are presented in Figures 5-5 a, b and c along with the results from the FSAR double ended steamline transient. To compare the second phase of the transient, the FSAR steamline break responses were shifted such that the time of trip coincides with initiation of the FSAR steam line break accident. It has been confirmed that the results are the same as those presented in the FSAR and the consequences are shown to be acceptable.

5.2.6 INDIVIDUAL SAR TRANSIENTS AND ACCIDENTS

Having analyzed the typical transients, a review of each SAR transient and accident was made considering the results presented in the earlier sections to show that the consequences of the transients and accidents are acceptable.

5.2.6.1 Transients Considered

A. Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition. Not applicable since turbine is not functioning at initiation.

B. Rod Withdrawal at Power. There is a wide spectrum of transients analysed in the FSAR. These analyses show that for a slow control rod assembly withdrawal from power, the reactor trip on overtemperature ΔT occurred after a longer period than the rapid RCCA withdrawal. Further, for the 10 percent and 60 percent power cases, the results are similar to the 100 percent case except that as the initial power is decreased, the range over which the overtemperature ΔT trip is effective is increased. Hence, a 100 percent power case with mini- mum insertion rate was analysed for this study. It is shown that for a generic three loop plant, even considering a stuck rod (CASE D), the consequences will be the same as those presented in the DESLB at hot shutdown analysis. These results were confirmed by running a 60 percent power case.

C. Dropped Full Length Assembly or Assembly Banks. The FSAR analysis showed that the system essentially returned to a new steady state equilibrium condition without a reactor trip. Hence, not limited by turbine trip failure.

D. Uncontrolled Boron Dilution. This transient is shown to be limited by RWAP with minimum insertion rate. Boron dilution accident at power is terminated by operator action 15 minutes after reactor trip and no actuation of protection system is considered after reactor trip in the FSAR analyses. But for RT without turbine trip following this dilution transient, the low steamline pressure signal will activate SIS and the system realigns and dilution is terminated. The return to power will be similar to that of RWAP transient with less shutdown and hence, the consequences will be the same as that of DESLB in the FSAR.

E. Boron Dilution at Standby. Turbine not operating.

F. Partial Loss of Forced Reactor Coolant Flow. The FSAR analyses showed that the low loop flow caused the reactor trip. After the trip, if a cooldown proceeds, then it will fall in the same group of transients where the consequences will be bounded by DESLB transients and this has been verified for the case where the non isolated loop was different from the pump failure.

G. Loss of Load. Turbine trip is initiating event. Not applicable.

H. Startup of an Inactive Loop. This transient is very similar to a rod withdrawal at power except that the reactivity insertion is due to the cooler fluid in the one loop entering the core. The reactor trip occurred by the high neutron flux reactor trip. This transient after the trip will be similar to RWAP transient and hence the consequences will be the same as that of the analysis in the FSAR.

I. Loss of Normal Feedwater/Blackout. Following the loss of feedwater, steam generator level will decrease until it reaches the lo-lo steam generator level set point generating Reactor Trip, and it has been shown that the cooldown from different initial transients are bounded by HZP steamline break transient and hence the consequences will be the same as presented in the FSAR, for a cooldown after the reactor trip.

J. Feedwater Malfunctions. The excessive feedwater will cause an increased load on the secondary side causing moderator feedback to increase core power until the steam generator fills to generate feedwater isolation on high-high steam generator level. The reactor trip occurs at low steam generator level and if a cooldown continues, the results will be similar to the typical case analyzed and hence the consequences will be the same as that of the analysis in the FSAR.

K. Excessive Load Increase. The increased load on the secondary side cools both the secondary and primary sides causing a reactivity insertion due to moderator feedback. Typically no trip condition is reached and the plant stabilizes at some higher than nominal power yielding no initiating event for the turbine trip failure event.

L. RCS Depressurization. An RCS Depressurization will cause the RCS pressure to decrease until the low pressurizer reactor trip setpoint is reached. The return to power case is similar to the typical case and the consequences of no turbine trip are bounded by the FSAR analysis.

M. Inadvertent Operation of the Emergency Core Cooling System (ECCS) During Power Operation. When the ECCS comes on at any time, boron begins to be introduced into the core causing a gradual reactor shutdown due to boration. Not assuming the turbine to function should a reactor trip occur on low steamline pressure would not lead to adverse consequences due to the large amount of boron in the RCS.

N. Complete Loss of Flow. This transient may result from a simultaneous loss of electrical supplies to all reactor coolant pumps. The immediate effect of loss of coolant flow is a rapid increase in the coolant temperature, but the reactor trip on reactor coolant pump bus undervoltage avoids any fuel damage. A comparison of the core flow and power with and without offsite power for steamline break accident (WCAP-9226), showed the case with offsite power is more limiting than the case without offsite power. Hence, the FSAR DESLB analysis will bound the cooldown phase of complete loss of flow.

5.2.6.2 Accidents Considered

It has been demonstrated that potential failure of the turbine stop valves is a very low probability event. In considering the transients additional failures were assumed to increase the severity of the transients. The various accidents (Condition III and IV events) include events where a break is assumed in the secondary piping and those events where the secondary side is not breached.

For those events where the secondary side is intact, the results are very similar to those presented for the transients. Namely, the consequences are nearly identical to those presented in the FSAR if all the MSIV's function and if further conservative assumptions are made, the results will be only slightly worse than the SAR case.

For the steamline break and the feedline break, the SAR results will be bounding if all the MSIV's function or if the MSIV fails in the faulted loop. The assumed case of a failed MSIV pair in another loop, causing multiple steam generator blowdown is discussed in Section 5.4.

5.3 LOCA ANALYSIS

The impact of no turbine trip on small or large break LOCA and steam generator tube rupture was qualitatively assessed with the following results:

A. For all cases, proper operation of the MSIV's will preclude any significant effect. Steamline isolation occurs very early in the large break LOCA accident, thus mitigating any cooldown at its start. Steamline isolation would occur as a result of the blowdown for many of the small break cases initially allowing a cooldown to occur. This cooldown would result in greater heat removal capability in the steam generators which would be a benefit improving analytical results. In the case of a steam generator tube rupture, MSIV's closing may be accomplished either manually by procedural action or automatically due to the blowdown. In any event, the blowdown would be short term and have only minor impact.

B. In the extreme situation that one steam generator remains unisolated and the turbine does not trip, small break LOCA would again be benefited by the increased blowdown. For large break LOCA, a blowdown of a steam generator, in addition to the LOCA, could result in some small increase in calculated peak clad temperature. However, the impact would not result in a significant increase in radiological release.

   The consequences of failure to isolate a steam generator in conjunction with no turbine trip are probably most significant for the case of a steam generator tube rupture. If the blowdown occurred in the faulted steam generator, releases would be increased and the break flow would continue until the primary system could be depressurized to nearly atmospheric pressure. If the blowdown occurred in a non-faulted steam generator, the consequences of a tube rupture would not be significantly different.

The scenarios in B above for a typical plant are extremely unlikely. The three events of concern must first occur, followed by failure to isolate one steam generator and additionally, failure to trip the turbine. For a plant with a single MSIV in each steam line, the most likely of these scenarios would occur with a probability of approximately 10^{-9}. For the special case of Farley Nuclear Plant, the

redundant MSIV's in each steamline preclude a single MSIV failure resulting in non-isolation of a steam generator. The scenarios in B then would become even more improbable. For the Farley Plant, failure of the turbine to trip following a LOCA or tube rupture would not exceed the licensing basis, even assuming single failure of a MSIV.

5.4 MULTI-STEAM GENERATOR BLOWDOWN

Westinghouse in conjunction with the Westinghouse Owner's Group (WOG), has been involved in evaluating the ramifications of multi-steam generator blowdown. Westinghouse is preparing an emergency operating procedure for the WOG which will eventually be submitted to the Nuclear Regulatory Commission along with the appropriate basis document. It should be noted that Farley Nuclear Plant has redundant MSIV's in each steamline, i.e. a single failure will not result in an unisolated steam generator.

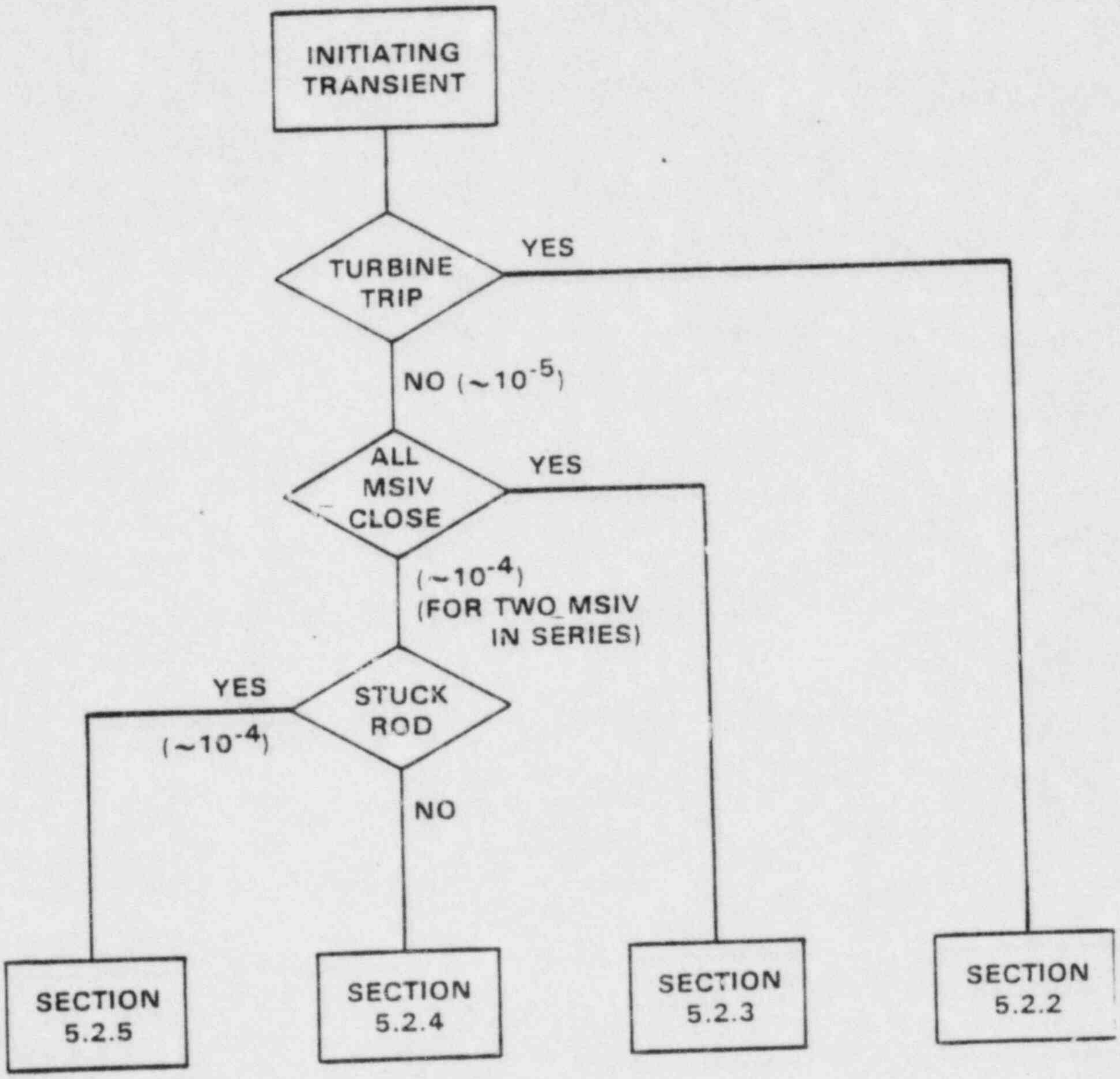


Figure 5-1 Flow Diagram

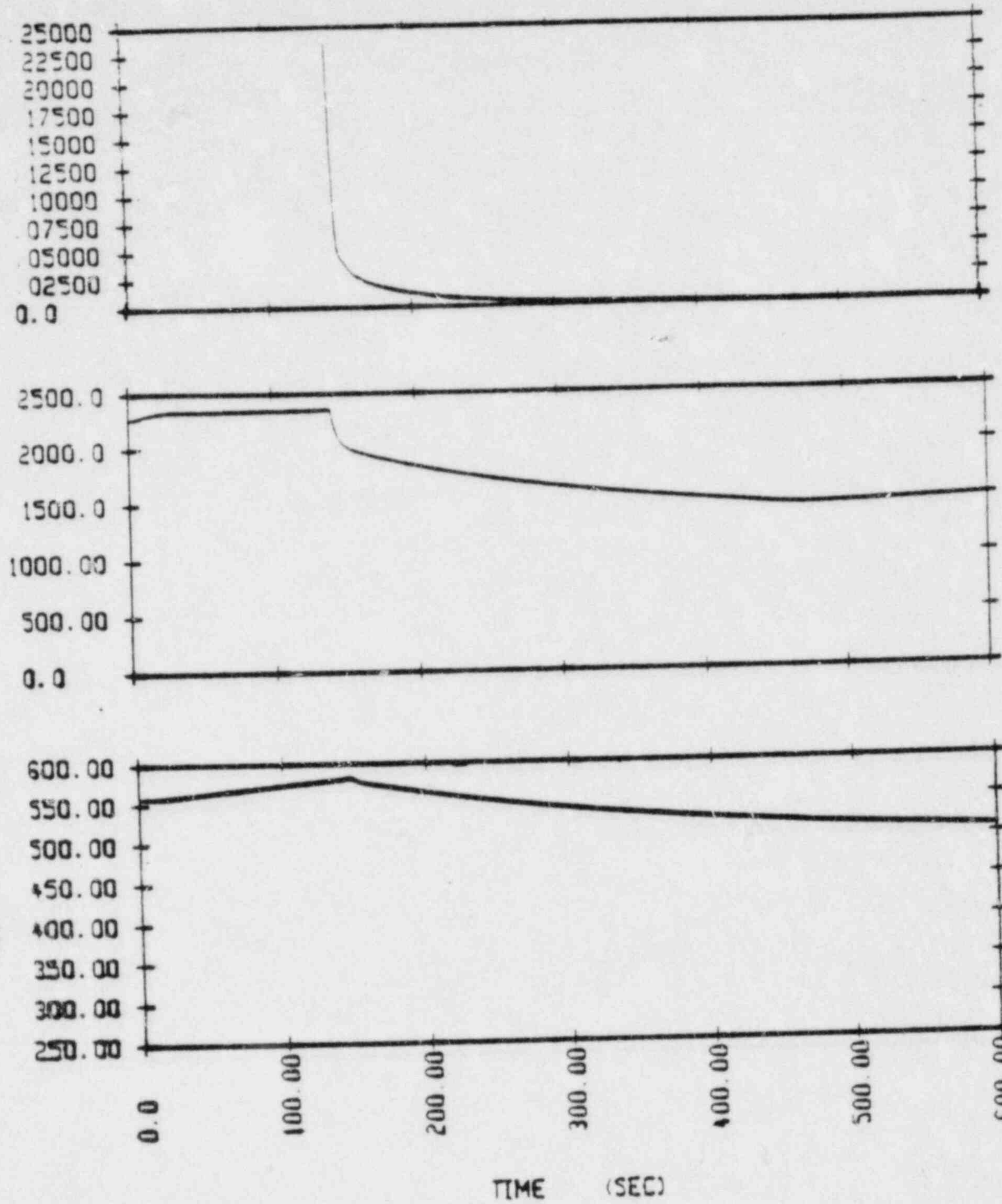


FIGURE 5-2 TYPICAL RWAP - FSAR ANALYSIS CASE A

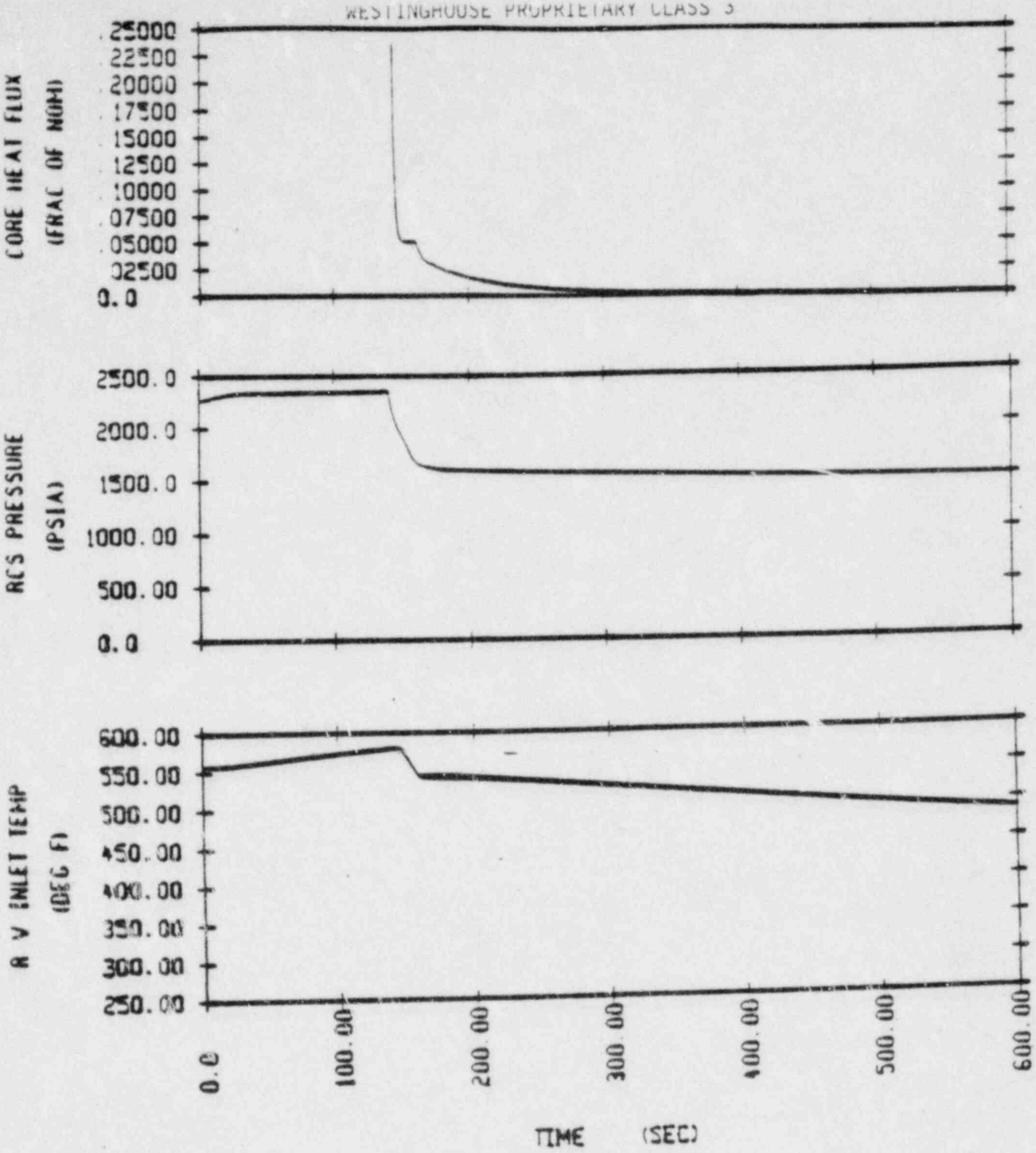


FIGURE 5-3 TYPICAL RWAP - NO TT ON RT, MISV CLOSED
CASE B

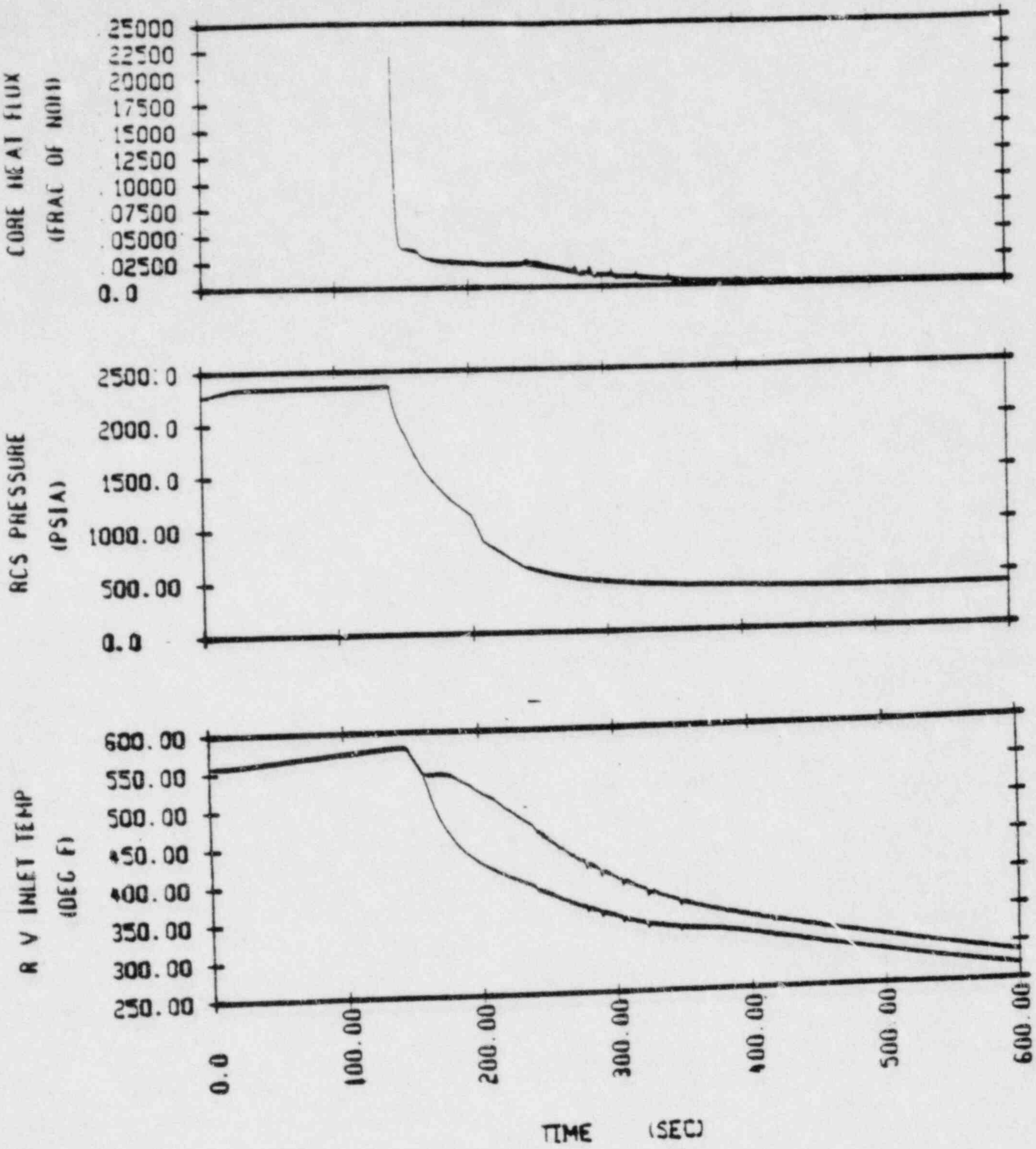
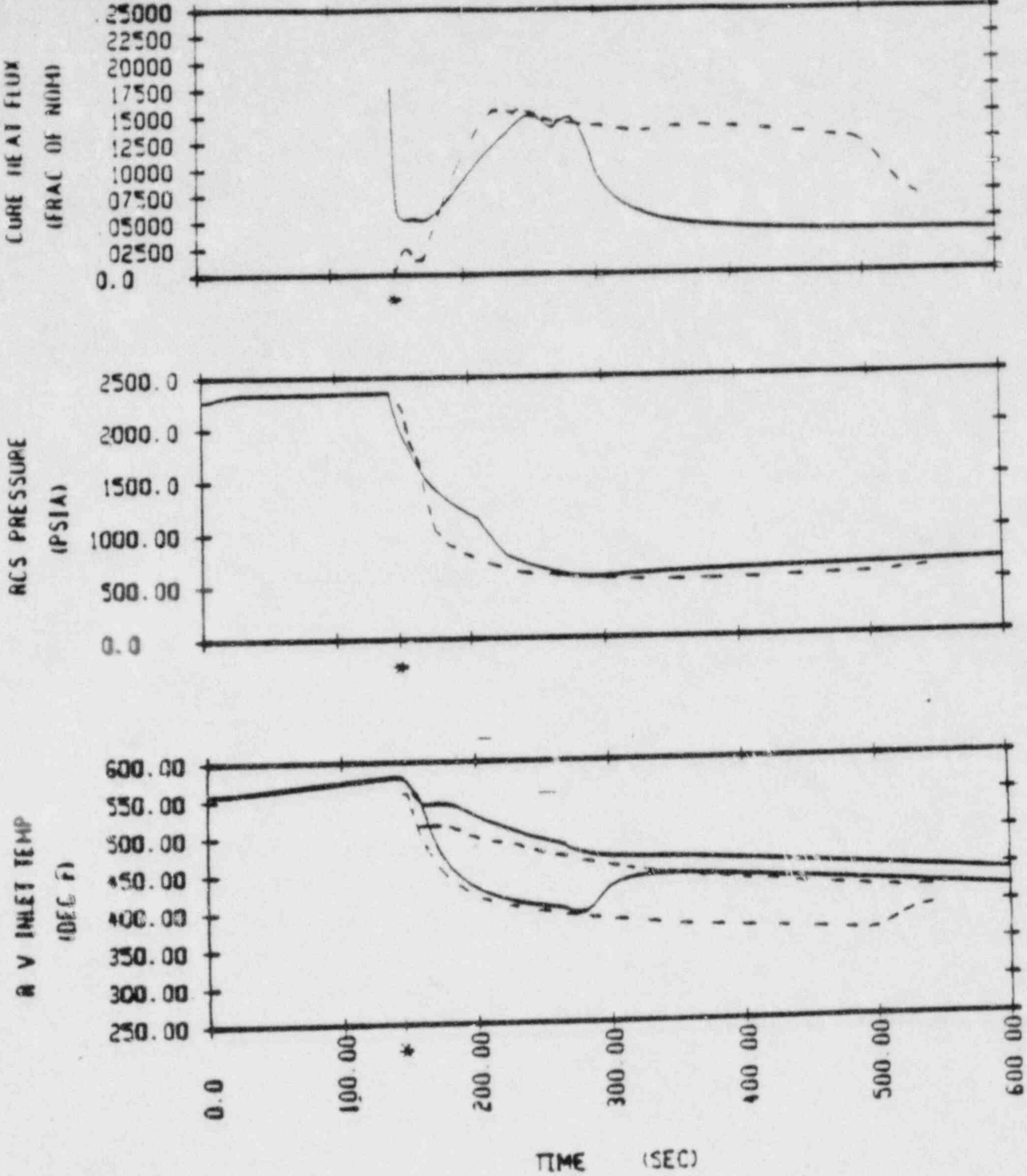


FIGURE 5-4 TYPICAL RWAP - NO TT ON RT, MSIV FAILURE, NO STUCK ROD - CASE C



---- DESLB

* = TIME AT TRIP OF RWAP = START OF STEAMLINE BREAK

FIGURE 5-5 TYPICAL RWAP - NO TT ON RT, MSIV FAILURE, STUCK ROD - CASE D

6.0 CONCLUSIONS

The intent of this report was to evaluate the influence of turbine valve testing on turbine trip system reliability and discuss the necessity of having technical specification requirements on turbine valve testing. The approach taken was to evaluate based on current data the physical aspects of testing, the probabilistic aspects of testing and the analytical aspects of testing. To aid in summarizing the results of these various sections of the report, each will be discussed individually followed by an overall summary.

6.1 VALVE TESTING

In Section 3 it was concluded that valve failure is independent of periodic valve testing. This conclusion was based on the undemonstrated ability of valve testing to identify failure precursors and influence valve lifetime by identifying necessary repairs. This conclusion was supported statistically in Section 4 by comparing observed failure rates for different testing schemes. The result of this statistical evaluation was that there was no difference in valve failure rates for weekly, monthly or irregular testing. Westinghouse then, is confident in stating that though periodic testing does influence calculated valve availability, periodic testing does not influence valve failure rate and that increasing the test interval will have no adverse impact on the valve failure rates.

6.2 TURBINE OVERSPEED AND MISSILE GENERATION

Three cases of overspeed were evaluated to determine the impact of increasing the valve test interval on turbine overspeed probability. Those cases were destructive overspeed, design overspeed and intermediate (130 percent) overspeed. Further each overspeed event was viewed with respect to the ability to generate a missile assuming that the particular overspeed event occurred. These overspeed events are discussed separately below.

Destructive Overspeed - The probability of destructive overspeed (which is also the probability of no turbine trip) was shown to be less than 7×10^{-6} per year considering yearly testing of turbine valves, using a 95 percent UCB estimate of valve failure rate and 3 separations per year. Assuming a missile is generated whenever destructive overspeed is reached results in a missile generation probability of the same value ($<7 \times 10^{-6}$ per year). This value is well below missile generation probability guidelines established by Spencer H. Bush in, "Probability of Damage to Nuclear Components Due to Turbine Failure" and Regulatory Guide 1.115, "Protection Against Low'Trajectory Turbine Missiles".

Intermediate (130 percent) Overspeed - The probability of a 130 percent overspeed event using a 95 percent UCB was shown to be approximately 7×10^{-5} without on-line valve testing. A true probability of missile generation at 130 percent overspeed was not available for this report, however, it is believed that the conditional probability of generating a missile at 130 percent overspeed would be at least one order of magnitude lower than the conditional probability of generating a missile at destructive overspeed. This value would be approximately equal to that for missile generation at destructive overspeed.

Design Overspeed - The probability of missile generation at design overspeed has been shown to be [ ]^{a,c} using the fault tree approach, taking credit for the particular protective features at Farley and using a P_2 value associated with a five year inspection interval of LP discs. Using operating experience and assuming a five year LP disc inspection results in a missile generation probability of [ ]^{a,c} per demand. Using either approach results in a low design overspeed missile probability.

Concerning the impact of increasing valve test interval, the evaluation of design overspeed showed little sensitivity to performance of less frequent testing i.e. this event is not driven by the frequency of testing but rather the probability of component failure which is

independent of test interval. The insensitivity of this event to test interval does not support maintenance of frequent testing now being performed.

Missile generation probabilities for all cases of overspeed analyzed for this report are low when compared to published guidelines even considering yearly testing. The current requirement to test turbine values weekly is not supported by these results.

6.3 SAFETY ANALYSIS

Section 5 of this report demonstrated the acceptability of not tripping the turbine in terms of the accident analysis. For Condition I, II, III and IV non-LOCA events (excluding continued multi-steam generator blowdown) the FSAR was shown to be bounding. In the case of LOCA type events and multi-steam generator blowdown the Farley MSIV arrangement precludes a single failure resulting in an unisolated steam generator rendering the consequences of no turbine trip insignificant. Additionally these events were shown to be highly improbable.

6.4 SUMMARY

Based on the results of this study Westinghouse is confident that testing turbine valves no more frequently than yearly is adequate to satisfy any concerns associated with turbine trip system malfunction as it impacts licensing requirements. This conclusion is primarily based on the high reliability of the turbine trip system and the minimal consequences associated with its failure.

Concerning technical specification requirements on turbine valve testing the following should be considered. An evaluation of the frequency of occurrence of turbine shutdowns showed that on the average a plant shuts down 6 times a year. Even if a plant shuts down only to refuel, the average refueling period is 1 year and the turbine value test requirement is satisfied and, it might be added, independently of technical

specification requirements. Based on the foregoing discussion, Westinghouse does not see a need for continuance of the technical specification requirement on turbine valve testing.