EGG-ID-6037
September 1982

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Report on Diagnostic Instrumentation Evaluation

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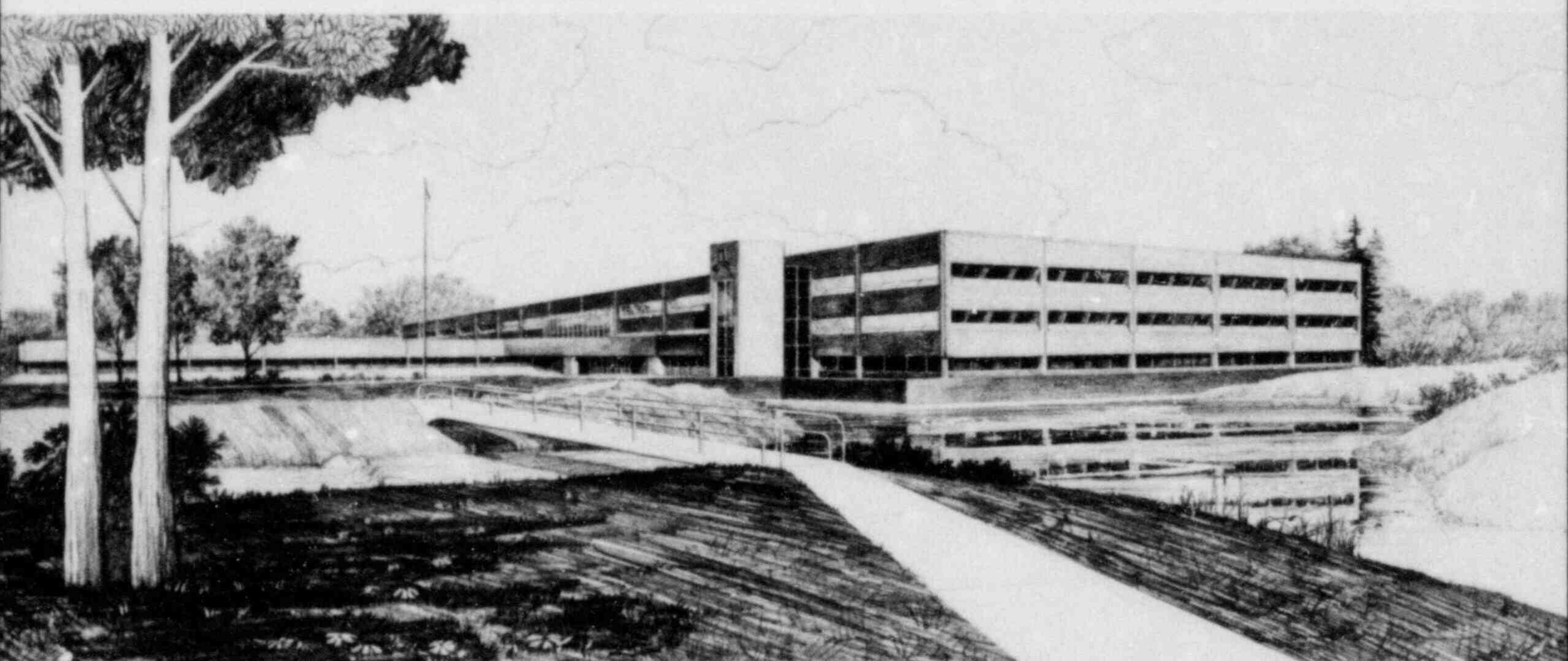
Operated by the U.S. Department of Energy



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Prepared for the
U. S. NUCLEAR REGULATORY COMMISSION
Under DOE Contract No. DE-AC07-76ID01570

EG&G Idaho

EG&G Idaho, Inc.

FORM EG&G 398
(Rev. 03-82)

INTERIM REPORT

Accession No. ________

Report No. EGG-ID-6037

Contract Program or Project Title: Diagnostic Instrumentation Evaluation

Subject of this Document: Identification of Anticipatory Measurements

Type of Document: Year-End Project Status Report

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Date of Document: September 1982

Responsible NRC Individual and NRC Office or Division: N. N. Kondic,
Division of Facility Operations

> This document was prepared primarily for preliminary or internal use. It has not received full review and approval. Since there may be substantive changes, this document should not be considered final.

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Prepared for the
U.S. Nuclear Regulatory Commission
Washington, D.C.
Under DOE Contract No. **DE-AC07-76ID01570**
NRC FIN No. A6380

INTERIM REPORT

ABSTRACT

A preliminary list of anticipatory measurements is constructed. These are measurements for predicting, and hopefully avoiding, potential accident conditions in light water nuclear power plants. The list was determined with the aid of safety-related event trees which are described in the report.

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1. INTRODUCTION

The objective of this work is to determine what measurements are necessary or useful in early detection of off-normal conditions in nuclear power plants. It is assumed that an early prediction of an accident condition will allow either complete avoidance of the accident or at least minimization of the severity of the accident. The primary concern is to avoid a gross breach of barriers (fuel cladding, reactor coolant pressure boundary, and containment) to the release of radioactive material to the environment. This report is a progress report discussing only the preliminary phases of the work.

In this report, the terms "anticipatory measurements" and "anticipatory instrumentation" refer to measurement systems which are useful in predicting dangerous conditions before the conditions actually occur, hopefully early enough to avoid occurrence of an accident. This report does not address the important, complementary goal of determining the plant status during or after the occurrence of an accident, except incidentally when a measurement is useful for both predictive and accident tracking purposes. Accident-tracking measurement requirements are specified in Regulatory Guide 1.97, and these requirements are being addressed in a separate project being done by EG&G Idaho, Inc. for the Nuclear Regulatory Commission.

A core outlet temperature measurement can be used as an example to illustrate the essence of anticipatory instrumentation. If the temperature exceeds some predetermined set point, a dangerous condition currently exists. By contrast, if the temperature stays within the acceptable range but shows an unexpected and abnormal gradual increase, the interpretation might be that a dangerous condition does not curently exist but is developing and will exist unless preventative action is taken. In this latter situation (gradually rising but acceptable temperature), the temperature measurement is used as an anticipatory measurement. In the former situation (temperature exceeds set point), the temperature measurement is used as an indicator of an existing dangerous condition, which is not an anticipatory function.

Many existing power plant measurement systems can yield anticipatory measurments with little or no modification. These are obviously very interesting, since they represent anticipatory measurments that can be implemented with minimal cost. For this reason, the measurements required by Regulatory Guide 1.97[1] are given special attention in this report. Similarly, anticipatory measurements which are included in the fundamental parameters list of the Nuclear Safety Analysis Center (NSAC)[2] deserve special attention, since they are more likely to be installed and used.

Currently there is considerable activity in trying to improve the man-machine interface in nuclear plants. The goal of this work is the enhancement of the operator's capability to correctly interpret and respond to potential and actual accident conditions. The approaches are varied, ranging from choosing the best color for a signal light to designing a totally computerized disturbance analysis system[3] which could effectively remove the human from the decision-making process. The general problem here is the optimal display of measurement results, rather than deciding what measurements should be made and how they might be obtained. This problem is beyond the scope of the present work and will not be addressed in this report.

Considerable effort has also been spent in determining the minimum parameter set for nuclear plant accident tracking (after the accident or potential accident condition has occurred).[2,4,5] This is parallel to, but distinct from, a goal of the present work, which is to determine a minimum set of anticipatory measurements for predicting accident conditions.

The methodology used to obtain the preliminary list of anticipatory measurements is described in Section 2. Section 3 describes the event sequences represented by the event trees used in this analysis. The preliminary list of anticipatory measurements is determined in Section 4. Section 5 gives design criteria and measurement ranges presently considered. The conclusions and recommendations are in Section 6.

2. METHODOLOGY

The method used in this analysis to assess anticipatory measurement requirements is based on event tree analysis. The particular event tree chosen is a modified form of the event tree developed by Chamany.[6] This particular event tree, which was initially developed for the determination of protective signals and settings for a nuclear power plant, is a very general type of event tree. The major difference between this event tree and the type of event tree found in WASH-1400[7] is that the analysis is started at the end point (e.g. breach of cladding) and the initiating event is reached by back tracing. This has the advantage that tracing back can be done on as rudimentary a level as one desires. At each event level, the possibility of getting signals indicative of the plant or subsystem status relative to the event or as a precursor to the event is examined.

The major reason for choosing this particular event tree is its generality. Considerable work has been performed on examination of accident sequences for design, validation and training.[7,8] These event trees generally postulate an initiating event and follow this event to its logical conclusion. The difficulty in applying these more specific event trees to the selection of diagnostic instrumentation is that each event tree must be examined separately to determine if additional or different events require other instrumentation. Reference 8, for instance, recommends a total of twenty-nine accident sequences to form an exhaustive set. Certainly many of the events are redundant; still, each sequence must be examined in detail to determine this. It would seem that errors of omission are less probable in the case where no prior assumption is made in the choice of initiating events.

The event tree analysis technique does not, however, fully address those systems and subsystems in which components may be degrading though not immediately affecting plant operations. The same is true of many safety systems which are used only intermittently. An example is a pump with a faulty bearing. The current to the pump may be increasing, the bearing temperature increasing though not surpassing a predetermined set point, and the bearing becoming more noisy, yet the pump head and flow rate are still within specification. The same type of problem may occur with pipe hangers, control or relief valves, or any number of other plant systems or components. The gap between the events in the tree and the accident precursors must be filled in by the developer of the anticipatory instrumentation; that is part of the present work.

The anticipatory measurement requirements identified by the event tree analysis are in many instances the same as other safety-related measurement requirements (such as those in Regulatory Guide 1.97) or the same as measurements used for normal operation and control of the plant. This leads to statements requiring certain measurements for anticipatory purposes when those measurements already exist for other purposes. Although it may at first seem silly to suggest a requirement for a measurement that already exists, such requirements are still stated, for completeness and to emphasize the anticipatory value of existing measurements.

3. EVENT SEQUENCE DESCRIPTION

The sequence described here apply primarily to indirect cycle water reactors. Notes are given in the event descriptions concerning application to direct cycle water reactors. The event trees for clad failure and breach of reactor coolant boundary, and their description here, are taken from Chamany et al[6] with some modification. The event trees for breach of containment were developed under this study. Futher study of these event trees is to be pursued in FY-83 along with examination of event sequences from WASH-1400[7] and other sources.

Figures 1, 2, 3 and 4 show the events that could lead to breach of cladding, breach of pressure boundary and breach of containment. In the following sections each event sequence will be elaborated.

3.1 Breach of Cladding

Figure 1 shows the events leading to possible clad failure (event 0). Unfortunately none of the events 1-4 are measured directly and in most cases they cannot be measured in a fashion which is useful to the Reactor Protection System (RPS). Events 3 and 4 are beyond monitoring while in service and the probability of event 2 can be minimized by monitoring and maintaining the correct chemistry of the primary coolant. The effect of event 2 to lead to event 0 is a time consuming process, and operator action should be sufficient to avert damage. An alarm therefore may be adequate to rectify the situation and a trip of reactor may be unwarranted. It is unfortunate that event 1 is not amenable to measurements due to engineering constraints. Elaborate indirect observations have therefore to be made to forestall event 1.

Events 5-7 lead directly to event 1; they must be interpreted correctly by available instrumentation and corrective action must be taken so that event 1 does not occur. Signals are available to observe these events.

One can now proceed with events 5, 6, 7 to arrive at the initiating events leading to these. Events 10, 11 12 are the initiating events leading to event 5. Event 10 includes all incidents connected with reactivity control agents, such as uncontrolled withdrawal of control rods, boron dilution, ejection of control rods, malfunction of reactor regulating system and flux peaking due to wrong control rod patterns. Event 11 includes all incidents connected with refueling. Event 12 encompasses all incidents connected with reactivity excursion due to feed-back; i.e. cold water accident in case of PWR, quenching of primary coolant due to loss of feed heating, and void collapse due to turbine trip in the case of direct cycle BWRs.

Consideration of the transient behavior of the plant is needed to study the effect of the initiating events leading to event 5. It is posible to start from the initiating events and determine what signals could be made available to the operator, until the final event (event 5 in this case) is reached. If it is observed from the transient behavior of the system that such initiating events lead to the final event, it is obligatory that the operator act on the first (in time phase) signal available. Results of evaluating signals related to events causing the reactor power to be high are described in Table 1.

TABLE 1. EVENTS LEADING TO HIGH REACTOR POWER

Event	Comments
10. (a) Control rod ejection	Direct signal normally available. Back-up signal from neutron flux.
(b) Uncontrolled control rod withdrawal/boron dilution	Ditto.
(c) Reactor regulating system malfunction	Signal may be available but it will be difficult to interpret.
(d) Wrong control rod pattern	Signal may be available, but difficult to interpret. Back-up signal from local neutron flux.

11.	Error in refueling or fuel shuffling	Direct signal difficult to instrument. Back-up provided by neutron flux (global/local) signal.
12.	(a) Cold water accident	No direct signal is available. Reactor inlet temperature relative to the reactor power level serves as back-up.
	(b) Turbine trip	Direct signal can be made available; however, it should be used only if primary coolant pressure and neutron flux excursions cannot be controlled by turbine bypass system (BWR) or primary coolant pressure excursion cannot be controlled by turbine bypass and primary pressure control system (PWR).
9.	Excess reactivity in the system	Can be made available with extra electronics/computing. Since the signal is derived from neutron flux with a delay it is of less merit than the neutron flux signal itself. However, it can be used as a back-up for neutron flux signal.
8.	High neutron power, global and local	Direct signal is possible through neutron instrumentation.

These results reveal that the neutron power signal is the earliest available signal in the chain of events. One can therefore conclude that this signal should be included in the anticipatory instrumentation. It is also clear that signals associated with LOCA should be included in anticipatory instrumentation. Trip setting for the neutron power signal can be obtained with the help of system dynamics studies. The value should be such that any initiating event will not lead to clad temperature higher than the permissible limit, loss of DNB margin to unsafe limit, boiling of primary coolant (PWR) or high primary coolant pressure.

High reactor power is also manifested in high outlet coolant temperature and high primary coolant pressure. These signals can be made available as a back-up in the case of common cause failure of neutron flux scram signal, although they are delayed. It is clear therefore that at least one of these signals should be included in the anticipatory measurements to guard against common cause failure of neutron flux scram signal. With the help of dynamic analysis of the system assuming failure of neutron flux scram signal, trip setting on these signals could be obtained, criteria of trip setting being the same as for neutron flux signal.

Events 5 and 13-16 are the events which lead to event 6 (inadequate heat removal by the primary coolant system).

Figure 1 illustrates the event trees leading to event 6 (inadequate heat removal by the primary coolant system). Primary coolant temperature and pressure signals are available to monitor this event. However, these signals do not offer any protection against event 13 leading to event 6. Tracing back from events 14 and 16, the initiating events 17, 18, 19, 21, and 22 are arrived at. The possibility of deriving signals for the event chains starting with events 17-22 is described in Table 2.

TABLE 2. EVENTS LEADING TO INADEQUATE CORE HEAT REMOVAL

Event	Comments
21	No direct signal available.
22	Available from pump speed or electrical supply for the pumps.
16	Signal available. However, flow measurement system has to be introduced.
17	Not available. Primary coolant pressure, pressurizer water level have to be used.
18	Available if these valves are instrumented. Otherwise by primary pressure and pressurizer water level.
19	Ditto.
15	No signal available.

The initiating events can be classified into six groups:

(i) Events 18 and 19, concerned with spurious opening of valves and stuck open valves connected to the primary coolant system.

(ii) Event 17, breach in the primary coolant boundary.

(iii) Event 22, loss of primary pumps.

(iv) Event 21, blockage of flow path.

(v) Event 13, crud deposition on fuel surface.

(vi) Event 15, change in heat transfer coefficient, film boiling.

Although direct signals for events 18 and 19 may be available, their use as anticipatory measurements becomes conditional, since the presence of some of these signals indicates that an abnormal condition already exists in the plant.

No direct signal is available for event 17, so primary coolant pressure and pressurizer water level have to be used. Protection against common cause failure of pressure instrumentation is needed.

For event 22, direct signal is available and it is the earliest in the chain of events, hence its inclusion as an anticipatory measurements is obligatory. In the case of common cause failure of this signal, the next in the chain that can be used is the low flow signal. It is apparent that so far as event 22 is considered as the initiating event, apart from the direct sensing of pump trip, only one of the signals, i.e. low flow or high outlet temperature of primary coolant signals, is necessary. However, the trip setting for these has to be arived at by dynamic analysis as illustrated before.

Event 21 can be classified into two categories: (a) global blockage; (b) local blockage. No direct signal is available for these events. For global blockage, primary coolant flow serves as a back-up indication followed by primary coolant outlet temperature. For local blockage in the case of LWRs no indication is available whatsoever.

For event 13 apparently there is no signal available.

For event 15 there is no signal available; however, primary coolant flow may be used as a preemptive signal in some cases.

The foregoing analysis reveals that to guard against event 6 the following process variable should be included as anticipatory measurements.

(i) Primary coolant flow

(ii) Sensing of loss of primary coolant pumps

(iii) Primary coolant pressure

(iv) Primary coolant outlet temperature

(v) Pressurizer water level (PWR)

(vi) Reactor water level (BWR).

Tracing back from event 7 (high inlet temperature of reactor primary coolant compared with reactor power level) eventually leads to initiating events 26-37. Measurement of the inlet temperature is valuable since all disturbances in the secondary coolant systems and beyond reflect in this reactor state variable at the earliest time phase. Subsequent changes in reactor outlet temperature and primary coolant pressure occur and serve as back-up signals. Analysis of the chain of events is in Table 3.

TABLE 3. EVENTS LEADING TO HIGH COOLANT INLET TEMPERATURE

Event	Comments
7	Signal available. However, it has to be related to the reactor power level. Back-up provided by primary coolant outlet temperature and primary coolant pressure.
25	Signal available. Low water level in steam generator.
24	No direct signal available.
23	Direct signal available but difficult to interpret.
26	Direct signal available.
27	Ditto.
28	Ditto.
29	No direct signal available.
30	No direct signal available. However, water level oscillation and feed water flow oscillations reveal the phenomenon.
31	Direct signal is possible. Its use has to be examined by dynamic analysis. Boiler water level and feed water flow serve as back-up.
32	Direct signal is possible.
33	No direct signal is possible. Boiler water level serves as back-up.
34	Direct signal is possible. However, it is difficult to interpret. Boiler level and boiler pressure serve as back-up signals.
35	Ditto.
36	No direct signal is possible. Boiler level and boiler pressure serve as back-up.
37	Direct signal is possible. However, it is difficult to interpret and its use needs close examination.

This analysis clearly demonstrates that the two signals generated by steam generator water level and reactor inlet temperature guarantee protection against the initiating events 26-37 originating in the secondary coolant system and beyond. Transient analysis of the system is required to find out the excursion of process variables due to these initiating events and the proper settings for the two signals have to be determined accordingly. It is of interest to note that although direct signals preceding these two signals may be made available, their use needs careful evaluation. It is clear that the steam generator water level is a parameter which should be included as anticipatory instrumentation. Reactor inlet temperature of primary coolant serves as a back-up in the case of failure of steam generator water level signal. However, this signal has to be weighed with respect to the reactor power level. If reactor inlet temperature is included, its setting has to be determined taking into account failure of boiler water level signal.

In case of absence/failure of reactor inlet temperature, back-up is provided by reactor coolant outlet temperature and reactor coolant pressure although time delays are involved. Trip settings for these must take into account the time delays.

3.2 Breach of Primary Coolant Boundary

Figure 2 represents the event tree associated with breach of primary coolant boundary as the final event. Of the first level initiating events 39-45, items 39 and 40 can be minimized by routine inspection and maintaining the proper primary coolant chemistry. Item 41 is, in some cases, impossible to anticipate and is currently considered in plant design. Items 42-45 can be instrumented directly. It may be possible to recognize items 42 and 43 (excessive vibration and failue of valve or pump seals) before the problem is so serious that it becomes plant threatening. Item 45, the failure of the check valves which isolate the low pressure injection sytem (LPIS) from the pressure of the primary coolant system, could result in a LOCA which bypasses the containment system. If these valves fail, a low pressure system will be exposed to the high pressure of the Primary Coolant System (PCS).

The failure or leakage of one of these valves can be diagnosed by appropriate pressure measurements and their interpretation.

Item 44 (high pressure of reactor PCS) is of course measured directly. The events which lead to this condition are items 1, 5, 23, 24 which have been discussed in the previous section.

The most obvious indication of an actual LOCA is the PCS pressure. In addition, back-up signals from measurement of pressurizer level, containment sump level, containment pressure and containment temperature are available; however, they must be interpreted correctly to be reliable.

3.3 Breach of Reactor Containment

Figure 3 shows the events which may lead to breach of containment, event 100, for a PWR. Event 102 is addressed in the design of containment vesels and cannot be anticipated. The probability of a threat due to event 104, the presence of a material defect, can be minimized through adequate quality control and periodic monitoring.

Event 101, the breach of the LPIS, is caused by event 106, the failure of the LPIS check values which isolate the LPIS from the reactor PCS. If these valves fail, the LPIS, which is located outside of the containment vessel and is not designed for PCS pressures and temperature, may fail. This would result in a LOCA and subsequent release of radioactive material which does not result in a containment failure. For this to occur both valves must fail. The status of these valves could be monitored with appropriately placed pressure transducers and acoustic monitors to determine partial failure or leakage. The assumption is that the probability of both valves failing at the same time is extremely small.

The other event which may lead to containment failure and release of radioactive material is for the containment pressure to be high, event 103. The failure in this case is either through exceeding the containment design specifications (material strength) or through the failure of a seal on one of the many electrical or hydraulic feed throughs. Breach may be recognized by monitoring containment pressure and temperature, and by monitoing containment area and plant area radiation levels. The containment pressure vent valve status must also be monitored. Scheduled inspection should be adequate to detect deterioration and failure of seals for containment feed throughs, as long as the failure is not directly caused by an abnormal condition such as high pressure or temperature (above the seal design range).

Assuming that breach of the primary pressure boundary has occurred, high containment pressure may be caused by two main occurence, events 107 and 108. The occurrence of event 108 can be avoided by monitoring the containment H_2 concentration and possibly igniting the mixture under conditions where a burn rather than an explosion will occur. Event 107, the failure to adequately remove energy from the containment vessel and thus control the containment pressure, may be caused by the failure of one or more subsystems, events 109, 114, 120 or 121. The analyses of these events are as follows:

TABLE 4. EVENTS LEADING TO INADEQUATE CONTAINMENT HEAT REMOVAL IN A PWR

Event	Comments
109 Reactor power high	Reactor power is indicated by neutron flux readings.
112 Neutron absorbers absent/ diluted in ECC water	Measurement can be made directly on RWST or in boric acid charging system.
113 Failure of plant to scram	Control rod position and velocity will yield useful information. Neutron flux is a possible back-up, however subject to interpretation problems.
114 Inadequate cooling of containment spray	Coolant temperature is easily measured directly.
115 Heat exchanger fouling	This is generally a long term problem and should be detected during regular inspections etc.

116	Inadequate CS heat exchanger coolant flow	Can be directly instrumented with flow meter, alternate measurement could be heat exchanger ΔT on primary or secondary side.
117	Flow blockage	Blockage due to damage/loose part is difficult to instrument directly, back-up signal available from coolant flow depending on measurement location. Blockage due to incorrect valve position may be instrumented directly.
118	Loss of pumps	Can be instrumented directly and in addition early warning of failure possible through monitoring pump current, head, vibration and noise.
119	Inadequate coolant supply	Can be instrumented directly at source, such as tank or supply level, etc.
120	Loss of containment spray	Direct instrumentation of total loss made by flow measurement, barring downstream piping failure; partial loss much more difficult to instrument.
122	Flow blockage	Complete blockage same as event 20; partial blockage difficult to instrument.
123	Loss of CSR pump	Same as event 118 above; pump can be destroyed by running with insufficient containment sump water level.
124	Inadequate containment sump water level	Can be instrumented directly.
125	Inadequate ECC injection	ECC injection instrumented directly, inadequate amount or total failure may result in inadequate liquid to cool reactor and containment.
126	Flow blockage	Same as event 117.
127	Loss of HPIS or LPIS pump	Same as event 118.
128	Inadequate level maintained in RWST	Can be instrumented directly.
121	Containment heat exchanger system malfunction	Difficult to instrument directly but some information can be obtained through interpretation of ΔT and flow.

129	Inadequate primary flow (LPIS)	Can be measured directly.
130	Inadequate secondary flow	Can be measured directly.
131	Fouling of heat exhanger	Same as event 115.
132	Loss of pumps	Same as event 118.
133	Flow blockage	Same as event 117.
134	Flow blockage	Same as event 117.
135	Loss of pumps	Same as event 118.
136	Inadequate coolant supply	Same as event 119.

Figure 4 shows the events that may lead to a breach of containment for a BWR. Some of these event sequences are the same as for PWRs, but others are quite different.

The problems of material defects and external events in BWRs are similar to those in PWRs. The event sequences for high containment pressure and containment isolation failure in a BWR are given in Table 5.

TABLE 5. EVENTS LEADING TO HIGH CONTAINMENT PRESSURE AND CONTAINMENT ISOLATION FAILURE IN A BWR

Event		Comments
204	Containment isolation failure (seals or valves)	Most modes of containment isolation failure are not directly detectable.
230	Isolation valve failure	Some failure modes are easy to detect, others require sophisticated measurements and interpretation.
231	Seal failure	Seal degradation leading to failure should be detectable through scheduled inspections.
203	Containment pressure high	Directly measureable.
220	Atmospheric dilution system failure	Detectable through gas flow measurements.

221	Hydrogen explosion	Explosive concentrations of hydrogen can be measured directly.
222	Ventilation system failure	Detectable through temperature measurements.
223	Inadequate heat removal from containment	Detectable through temperature measurements
225	Vacuum breaker system failure	Detectable through pressure measurements.
224	RHR system failure	Detectale through suppression tank temperature measurements.
251	Improper water level	Can be measured in various ways, including differential pressure.
250	Loss of containment spray	Detectable by flow measurement (see event 120).
210	Breach of high energy piping	Not directly measureable. Indirect measurement possibilities include acoustic noise measurements and coolar pressure measurements.

4. ANTICIPATORY MEASUREMENTS

In this sections, a tentative list of potentially useful anticipatory measurements is developed. Section 4.1 describes the extraction of a list of possible candidates for anticipatory measurements from the event trees described in Section 3. Section 4.2 gives descriptions of the less familiar measurements. Section 4.3 gives a preliminary evaluation of the several possible anticipatory measurements, with consideration of practicality and possible utility.

4.1 Event Tree Analysis Results

The event trees described in Section 3 identify various radioactivity-release accidents and specific component malfunctions (pump failure, for example) that can cause the accidents. Consideration of the observable symptoms and precursors of these component malfunctions yields the lists of anticipatory measurements and anticipatory instrumentation given later in this section.

Tables 6-11 summarize the accident conditions, or events, and the related component failures, or causes. These tables also list the Regulatory Guide 1.97[1] measurement requirements that are specific to the particular event-cause pair, and the tables also list other Regulatory Guide 1.97 measurement requirements that are not specific to the particular event-cause pair but may be useful as anticipatory measurements. Consider as an example event 10, reactivity insertion due to control rod or boron dilution, caused by uncontrolled change in boron concentration. As indicated in Table 6, Regulatory Guide 1.97 requires a boron concentration measurement to check on this possible accident cause, and it also requires a neutron flux measurement in connection with some other possible accident cause. The neutron flux measurement is listed with event 10 in Table 6 because it might be useful in anticipating this event-cause pair, even through Regulatory Guide 1.97 does not specifically require the neutron flux measurement in connection with this particular event-cause pair.

The comments in Tables 6-11 include mention of possible anticipatory measurements that are not among the measurements required by Regulatory Guide 1.97.

The anticipatory measurement candidates from Tables 6-11 are summarized in Table 12. This table also includes some measurement categories that are not included in Tables 6-11 because they are not specific to any one possible accident cause. Many of the measurement categories in Table 12 are standard and well-known; those that are not so obvious are discussed in Section 4.2.

Table 12 also indicates whether the measurements are required by Regulatory Guide 1.97;[1] whether they are included in the NSAC fundamental parameter list;[2] and whether they may have potential as anticipatory measurements, as judged in this preliminary EG&G evaluation.

The "Status" column in Table 12 indicates the current status of the measurement, in terms of availability of the instrumentation system and required development effort. The status codes have the following meanings:

1. The measurement already exists in the plant.

2. Instrumentation in the plant can easily be adapted to make this measurements.

3. The measurement technology is well known, and instruments are commercially available or can be built by vendors with no significant development work.

4. The measurement principles are well understood and success has been demonstrated in similar measurement applications, but development is required to accommodate the temperature, pressure, radiation, range requirement, chemical environment, etc.

5. The basic measurement principles are known, but the technique requires study and development; there is some question about the ultimate success of the measurement.

4.2 Measurement Descriptions

The measurements that are included in the Regulatory Guide 1.97 or the NSAC lists are presumed to be quite well known; the other measurements from Table 12 are described in the following paragraphs.

4.2.1 Pump Status

By "pump status", we mean all aspects of the pump (and the driving motor) condition that might affect pump performance. Specifically included in this category are pump misalignment; rotor inbalance; fluid dynamic forces associated with impeller irregularities; abnormal fluid condition in the pump, such as two-phase flow or cavitation; thermal stress during heating or cooling; bearing wear; and bearing lubricating oil deterioration. Possible anticipatory measurements based on these aspects of pump status are discussed in the following paragraphs.

Vibration monitoring is commonly suggested[9-12] for detecting several pump problems, including misalignment, inbalance, fluid dynamic forces, abnormal fluid conditions, and bearing wear. Vibration monitoring can be useful for all of these, although considerable skill and experience may be required to accurately interpret the observed vibration in terms of the specific failure mechanism.

Lateral motion of the spinning rotor may result from the same phenomena that can be detected by vibration monitoring. Detection of such lateral motion is not a standard measurement, but it should be possible with proximity transducers using capacitance or eddy current techniques. Rotor motion measurements in both transverse directions (perpendicular to the shaft) at several locations along the shaft length might be expected to give more detailed and more directly-interpretable information than vibration monitoring could give.

Fluid flow noise may be indicative of the fluid condition in the pump and of leakage through a seal, but this noise may be obscurred by noise and vibration from other phenomena.

Bearing temperature may be a good indicator of bearing condition. For those bearings with a circulating coolant, the amount of heat being carried away by the coolant may be a better indicator than bearing temperature of how much heat is being generated in the bearing. The change in oil pressure across the bearing may also be a useful bearing condition indicator.

If the fluid that leaks through a pump seal can be collected and its flow rate measured, this measurement is a direct indication of the condition of the seal.

A simple pump current measurement might indicate gross pump failures. However, a more sophisticated measurement, involving checks for either changes or inconsistenties in the relationships between pump current, voltage, power, speed, fluid flow rate, and pressure rise, might be a more sensitive predictor of pump problems.

4.2.2 Valve Status

The "valve status" category of abnormal conditions includes leakage through the seal; leakage past the seat; failure to open or close completely; failure to operate at all; abnormal fluid flow through the valve; and bent valve stems.

Small leaks, especially leaks past the seat, can be difficult to detect in an operating plant environment. Visual observation is perhaps the most effective way to detect seal leaks, especially if the leaking fluid contains boron which forms visible deposits around the leak. Unfortunately, many valves are not accesible for routine visual inspection. Acoustic emission or flow noise monitoring have been mentioned as methods of detecting leaks.[12,13] The disadvantages of acoustic methods are that the leak noise may be masked by other noise in the plant; the correct interpretation of the observed noise is more an art than a science; and, it would be expensive to fit every valve with acoustic sensors.

There may be a few situations in which the presence of a leak might be detected through the observation of anomalous values of pressure, temperature, chemistry, radioactivity, etc., in some fluid space near the valve. The feasibility of using such a system would have to be evaluated on a case-by-case basis.

Failure of a valve to open or close completely, or total failure of the valve operation, can be detected by simple valve position sensors after the problem occurs. Depending on the specific situation and on how much the valve travel is limited, this may be useful as an anticipatory measurement or it may be useful only as an indication of a failure that has already occurred.

Monitoring the power necessary to drive the valve may give an indication of future failure from such gradually-developing causes as dirt accumulation or gradual bending of the valve stem.

Measurement of the pressure drop across a valve could indicate imcomplete opening of the valve.

Valves driven by electric motors may suffer damage, primarily bent valve stems, from excessive application of torque. This may happen during motor stall conditions[14] or as a result of motor inertia after the electric power has been shut off at the end of the valve's travel.[15] Damage such as a bent stem may render the valve completely inoperable. A bent valve stem would not normally be noticed until an unsuccessful attempt to operate the valve. The bent stem condition-even minor bending not severe enough to impair valve operation-could be detected by several techniques including strain gauges on the valve stem, position sensors to detect lateral movement of the stem, and possibly monitoring of the electrical power input to the motor during valve operation. However, it seems more reasonable to simply use a well-designed motor-valve combination so that the excessive torque condition does not occur.

Flow noise or acoustic emission can be useful in detecting cavitation which can harm a valve.[16] Noise monitoring could also be useful in detecting excessive flow-induced vibration or chatter of relatively fragile valve parts such as diaphragms and bellows.[17]

4.2.3 Control Rod Velocity

The speed with which a control rod assembly moves during a major change in rod position may serve as an indicator of problems in the drive and control mechanism. Existing instrumentation is probably adequate for this sort of velocity measurement in which large rod motions are involved.

The velocity and amplitude of small rod position fluctuations during steady state plant operation may give some useful indications of plant status. Such measurements would probably require new instrumentation.

4.2.4 Instrument Integrity

If the instruments that monitor the plant status malfunction, the result could be a serious error in the operation and control of a plant which is otherwise functioning normally. Thus, diagnosis of instrument malfunctions is as important to plant safety as diagnosis of defects in the plant itself.

Instrument integrity diagnostic techniques can be divided into two categories, which will be called "active" and "passive". In passive techniques, the instrument output signals are studied with the instruments in their normal modes of operation. Various types of tests can be peformed with these signals, including checks on the noise characteristics (the signature) of the signals, checks on whether the signal is within the normal instrument operating range, and checks for consistency between redundant signals. This sort of passive verification of instrument performance has been the subject of a separate program conducted at EG&G Idaho, Inc.[18,19]

Active techniques for checking instrument performance involve doing something abnormal with either the instrument or the plant. For example, a thermocouple response time might be checked by driving a current pulse through the thermocouple (an abnormal operation for a thermocouple) and observing the time history of the thermocouple output immediately after the current pulse. Pressure transducers might be checked by introducing a pressure pulse into the system, perhaps by opening a pressure relief valve momentarily. Such active techniques for instrument diagnostics are not now common, but there may be a great potential in this area.

4.3 Preliminary Evaluation

It would be desirable to rank the measurements of Table 6 according to some criterion such as cost-benefit ratio, or perhaps a combination of importance and difficulty of the measurement. Unfortunately, such a ranking is very difficult, particularly in this early stage of this project.

4.3.1 Difficulty

Difficulty of the measurement is easier than importance to evaluate. Many of the measurements are aleady required by Regulatory Guide 1.97, and there would be no difficulty in implementing these as anticipatory measurements. Difficulties of some other types of measurement are discussed in the following paragraphs. Note that these are only preliminary evaluations.

Control rod position and velocity, valve position, and seal leakage should be quite straightforward to instrument to give measurements with adequate resolution.

Vibration, flow noise, acoustic emission, pump electrical and hydraulic parameters, lateral motion of rotating shafts, and bearing and oil temperatures are all quite easy to measure. However, these quantities may be only indirectly related to the parameters of real interest, such as bearing wear, rotor inbalance, cavitation, etc. How well these desired parameters can be determined from the measured quantities is not well known. This question must be resolved before the difficulty of many of the basic measurements can be assessed.

Instrument integrity respresents a very broad category of measurements. As has been mentioned, the use of passive techniques to monitor instrument integrity has been the subject of a separate project, and some preliminary but incomplete technology exists in this area. There are expected to be a number of fairly easy active techniques for assessing instrument integrity. The specific techniques would of course depend on the particular instrument in question. There has not yet been a comprehensive study of useful active techniques for diagnosing instrument malfunctions that might lead to an accident.

4.3.2 Importance

There are several ways one might attempt to rank anticipatory instrumentation in terms of importance to safety. One might rank according to the severity of the accident that would be anticipated, according to the frequency of occurrence of the accident, or according to some combination of severity and frequency. This choice of criteria for ranking is the first problem to be addressed in determining the importance of the various possible anticipatory measurements.

Effectiveness is one aspect of importance. Obviously, an anticipatory measurement is not very important if it is not very effective at predicting potential accident conditions. Anticipatory measurements can be divided into two classes, according to whether the prediction is based on measurements made at a single time or on trends measured over minutes or longer intervals. Gradual trends in the common reactor state variables may or may not be useful as anticipatory measurements. Determining whether they really are useful would be a major effort, involving studying the behavior of the variables during all plausible plant transients, both accident-related transients and normal operating transients. The apparent magnitude of this task makes it seem very difficult to determine the importance of potential anticipatory measurements which depend on measuring long-term trends in plant state variables.

It should be much less difficult, but still not always easy, to determine the importance of single-time measurements. The indirect measurements, such as vibration analysis used to determine bearing wear, are among the single-time measurements for which determining the importance is the most difficult. The direct single-time measurements are much easier to assess.

On the basis of frequency of occurrence, valve and valve actuator problems far exceed any other single component failure as a cause of safety-compromising events.[14,20-22] The importance of valve instrumentation is emphasized by the TMI accident. Adding consideration of the severity of the possible accidents suggests that only a few of the valves in a nuclear power plant would be important targets for extensive anticipatory instrumentation. Most valves would require simple instrumentation to measure stem position, or no instrumentation at all.

5. DESIGN CRITERIA AND RANGES

Regulatory Guide 1.97 presents three design and qualification criteria categories which provide a graded approach to instrumentation requirements, depending on the importance of the measurement to safety. In order of decreasing stringency, these categories are:

Category 1 for key variables;

Category 2 for instrumentation indicating system operating status;

Category 3 for backup or diagnostic instrumentation.

A key variable is defined as "that single variable (or minimum number of variables) that most directly indicates the accomplishment of a safety function."

Regulatory Guide 1.97 basically outlines the requirements for energizing instrumentation, channel availability, data display and recording, the single-failure criterion, and the applicable NRC documents for quality assurance for the three categories. Other criteria, including servicing, testing, calibration, removal from service, setpoint access, display location, and malfunction recognition, are also outlined and apply to all three categories.

All of the documents cited address only <u>accident-monitoring</u> instrumentation that enables the plant operator to follow the course of an accident and bring the plant under control and accomplish safe plant shutdown. These documents do not address instrumentation of the type that enables the plant operator to <u>anticipate</u> an accident by monitoring or indicating the degradation of systems or components whose failure will result in a plant accident. Designation of a variable as "anticipatory" does not, of course, preclude it from being included as another type. Such variables could readily be classified as Category 1, 2, or 3, as defined above, depending on their importance as anticipatory indicators, and there is no apparent reason why the design and qualification criteria for the three categories cannot be applied directly to anticipatory instrumentation. The only real difficulty is the determination of rank. It is felt by the authors that complete ranking of individual instrumentation cannot be accomplished at this time.

Table 13 contains the recommended instrumentation and ranges. Essentially all of the recommended ranges are the same as normal plant operating ranges, since anticipatory instrumentation is used when the plant is in apparently normal operation. This of course does not apply to measurements which are not standard, such as vibration surveillance; these ranges cannot be specified until further evaluation or development of the measurement is completed. Instrument response requirements have not been addresed. These must be determined through examination of normal and abnormal transients. The table is also vague concerning exact valve and pump locations. This determination is closely related to the ranking problem.

6. CONCLUSIONS AND RECOMMENDATIONS

A methodology based on a generalized event tree analysis has been applied to the determination of anticipatory measurements for nuclear power plants. These measurements are intended to anticipate or give early warning of approaching off-normal conditions which may compromise reactor safety. The application of this methodology has resulted in a list of measurements which may be important to the safety of nuclear power plants. These measurements fall generally into two categories. The first category is primarily plant state variables. The intent is to monitor the variables and their time history to provide the reactor operator with an early warning of off-normal conditions. The second group deals with the anticipation of component failure. Preliminary work suggest that diagnostics which have potential to determine degradation of plant components or instrumentation show considerable promise in anticipating failure before it actually occurs. Only a few key components need be fully instrumented. Measurements that would be monitored to detect degradation or failure are those identified in Table 12. Other key measurements as identified by other fundamental parameter studies might be included. Key systems (specific valves, pumps, etc.) need to be identified (perhaps by probabilistic risk assessment) and standard or at least acceptable techniques developed to anticipate failure. Currently most of the available techniques deal with rotating machinery or valve leakage. No techniques are commercially available to anticipate valve failure or instrument failure.

There are two major areas in which further work is needed before a final list of anticpatory instruments can be produced:

1. The potential anticipatory measurements should be ranked according to importance.

2. It must be determined how well measurements of indirect parameters (vibration, flow noise, acoustic emission, etc.) can predict the parameters of basic importance (bearing wear, seal leakage, rotor inbalance, etc.).

The ranking according to importance now appears to be difficult. A complete ranking analysis would be a very long and expensive project. It may ultimately be abandoned, with the result that importance would not be used as a concise criterion for selecting anticipatory measurement candidates for further development.

Determining relationships between the observed indirect parameters and the desired parameters of direct importance appears at the moment to be a large but not impossible task. It can easily be divided into a number of subtasks involving specific parameters, such as the relationship between flow noise and valve seat leakage. Some of these subtasks would be substantially simpler than others. Continuation of this project should probably include identification of some of these subtasks to be pursued.

Another important area of work that should be considered is developing techniques for diagnosing instrument performance. The decisions on exactly what to do in this area may depend partly on the conclusions reached in the two major work areas described in the three preceding paragraphs.

This preliminary study suggests three specific areas of work that might be productively pursued as a continuation of this project by the Instrument Development Branch of EG&G Idaho, Inc.:

1. Valve Status Monitoring by Acoustic Analysis

   The use of acoustic techniques to determine valve degradation seems to be good candidate for future work, both on the basis of importance of obtaining valve status information and on the basis of expected success of the technique. Preliminary work in this area has already begun, by the University of Maryland via a subcontract from EG&G.

2. Leak Detection and Location by Acoustic Analysis

The detection and approximate location of leaks in pressure boundaries (such as primary coolant piping) by acoustic monitoring seems feasible on the basis of presently available information. It is known that leaks generate acoustic signals, and there is a body of knowledge (incomplete for this application) on correlation and more sophisticated calculations useful in triangulation-like procedures for leak location. Leak detection is very important, since it is the earliest precursor to a set of potential accidents of a serious nature. The importance and good prospects for success of this measurement technique make it seem well worth studying.

3. Instrument Integrity Methodology Development

Verification of proper instrument function is clearly important to the safety of a nuclear power plant (and also in many other applications). Some work specific to the LOFT system has been done in this area, but this work is not complete in some respects and is not generally applicable. (The LOFT application work will not be continued in FY-83.) It is believed that there is a great potential for the development of quite simple and effective techniques for verifying the integrity of a variety of different instruments, including those used in measuring pressure, temperature, fluid flow, and control rod position. Work in this area should be very fruitful.

It is suggested that the future direction of this project be decided in discussions between Nuclear Regulatory Commission and Instrument Development personnel.

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TABLE 6. EVENTS RELATED TO HIGH REACTOR POWER

Event	Cause	Specific Measurement Required by Regulatory Guide 1.97 (Category)	Possible Signal Required by Regulatory Guide 1.97 (Category)	Comments
10 Reactivity insertion due to control rod or boron dilution	Control rod ejection	None	Control rod positions (3) neutron flux (1)	Direct signal difficult to instrument.
	Uncontrolled control rod withdrawal	None	None (1.97 requires full in or not full only for control rod position) (3)	If direct measurement of control rod position is available this signal could be differentiated.
	Uncontrolled change in boron concentration	Boron Concentration (3)	Neutron flux (1)	Interpretation of neutron flux requires knowledge of temperatures and control rod position.
	Reactor regulating system malfunction	None	Interpretation of neutron flux (1), control rod position (3), boron concentration (3) and cold leg water temp.	Difficult to interpret; requires detailed disturbance analysis system
	Wrong control rod pattern	None	Control rod position (3) neutron flux (1)	Difficult to interpret.
11 Error in refueling or fuel shuffling	Procedure error	None	Neutron flux (1)	After the fact, direct signal difficult to instrument and neutron flux difficult to interpret.
12 Reactivity insertion by feedback	Reactor inlet temperature too low	RCS Cold leg water temperature (1)		Reactor inlet temperature relative to reactor power is usually used.
9 Positive reactivity insertion	Unspecified	Neutron flux (1)		
8 High neutron power	Unspecified	Neutron flux (1)		

TABLE 7. EVENTS RELATED TO CORE HEAT REMOVAL

Event	Cause	Specific Measurement Required by Regulatory Guide 1.97 (Category)	Possible Signal Required by Regulatory Guide 1.97 (Category)	Comments
13 Crud deposition on fuel	Corrosion	None	None	Difficult to instrument, long term problem controlled by maintaining correct coolant chemistry.
14 Loss-of-coolant	17 failure of piping component or vessel	RCS pressure (1)		
		Coolant level in reactor (1)		Direct signal is difficult if not impossible to instrument--only indirect signals which are subject to interpretation are available.
		Pressurizer level		
		Subcooling (2)		Subcooling calculated from steam tables and measured temperature and pressure.
	18 Spurious opening of safety, relief or bypass valves	Valve position closed or not closed (2) or flow or pressure in relief valve lines (2)	RCS pressure Pressurizer level	Valve position should be a direct measurement of position, not indirect. Actual position is desirable. Some possibility of monitoring valve degradation also exists using long term surveillance and signature analysis techniques. Pressurizer level can be misleading.
	19 Stuck open relief or bypass valve	Same as 18 above	RCS pressure Pressurizer level	Same as above.
15 Change in heat transfer coefficient	5 Reactor power high	See Table 1.		
16 Low flow or loss of primary flow	21 Local flow blockage global flow blockage	None	Core exit temperature hot leg temperature	Difficult and costly to instrument
	22 Loss of some or all primary coolant pumps	RCS pump motor current (3)	Pump ΔP PCS flow rate	Full range PCS flow rate measurement should be required. Proper diagnostics could prevent actual loss of pump.
7 Reactor inlet temperature high	Unspecified	Core inlet temperature (1)		Diagnosis of cause appears in Table 3.

TABLE 8. EVENTS RELATED TO SECONDARY SIDE HEAT REMOVAL

Event	Cause	Specific Measurement Required by Regulatory Guide 1.97 (Category)	Possible Signal Required by Regulatory Guide 1.97 (Category)	Comments
25 Loss of secondary coolant	31 Loss of feed pumps	Main feedwater flow (3)	Steam generator level (1)	
		Emergency feedwater flow (2)		
	32 Stuck/closed feed water valves	Main feedwater flow (3)		Valve line up and valve status would also be useful.
		Emergency feedwater flow (2)		
	33 Rupture of feedwater line	Steam generator pressure (2)	Feedwater flow (3)	Measurement of feedwater flow is effective if rupture occurs upstream of measurement location.
		Steam generator level (1)		
	34 Steam generator relief valve open	Safety/relief valve position (2)		Valve position measurement should be a direct measurement. Value status also useful in anticipating incident.
	36 Steam line rupture	Steam generator pressure (2)		
		Steam generator level (1)		
	37 Insufficient feed water flow	Steam generator level (1)		
		Main feedwater flow (3)		If steam flow were measured a mass balance could be performed.
23 Secondary coolant temperature high	26 Steam generator isolation from turbine	Steam generator pressure (2)		Secondary coolant temperature is monitored directly
		Steam generator level (1)		
		Main steam flow valve position (2)		

TABLE 8. (continued)

Event	Cause	Specific Measurement Required by Regulatory Guide 1.97 (Category)	Possible Signal Required by Regulatory Guide 1.97 (Category)	Comments
	27 Turbine trip	None		Turbine problem might be anticipated by noise/signature surveillance.
	28 Generator load rejection	None		
24 Inadequate heat transfer from primary to secondary coolant	29 Steam generator tube fouling	None		Difficult to instrument; process is slow and controllable.
	30 Flow instability of secondary coolant	Steam generator level (1)		Requires time history to anticipate and recognize.
		Steam generator pressure (2)		
		Main feedwater flow (3)		

TABLE 9. EVENTS RELATED TO PRIMARY PRESSURE BOUNDARY INTEGRITY

Event	Cause	Specific Measurement Required by Regulatory Guide 1.97 (Category)	Possible Signal Required by Regulatory Guide 1.97 (Category)	Comments
44 High PCS pressure	Unspecified	RCS pressure		
	46 High energy transfer from fuel to primary coolant	See Table 1		
	23 Inadequate heat removal from primary to secondary	See Table 3		
	24 Secondary coolant temperature high	See Table 3		
	47 Additional energy release by metal water reaction	See Table 1		
39 Material welding defect		None		Generally a fabrication and periodic inspection type problem; might be addressed through noise surveillence.
40 Fatigue, creep and corrosion		None		Same as above
41 External events		None		Cannot be anticipated.
42 Vibration		None		Possible to instrument plant with accelerometers for early detection of deteriorating pipe hangers, flow induced vibration etc.
43 Failure of seals pumps and valves	Unspecified	None		Monitoring pump seal flow both inlet and outlet, and seal temperature for pumps and valve status diagnostics may anticipate complete failure
45 Failure of PRV, PORV or LPIS check valves				Same as above.

TABLE 10. EVENTS RELATED TO CONTAINMENT INTEGRITY IN A PWR

Event	Cause	Specific Instruction Required by Regulatory Guide 1.97 (Category)	Possible Signal Required by Regulatory Guide 1.97 (Category)	Comments
101 Breach of LPIS system outside of containment	106 Failure of LPIS isolation valves	None		Possible application of value status diagnostics.
102 External event (projectile, etc.)				Cannot be anticipated.
104 Material defect	Unspecified	None		Difficult to instrument but may be recognized through regular inspection; actual failure caused by high containment pressure.
105 Failure of feed through seal or isolation valve	Unspecified	Containment pressure (1)		May be anticipated through valve status diagnostics and regular leak rate test.
103 Containment pressure high	108 H_2 burn/explosion	Containment H_2 concentration (1)		
	107 Inadequate heat removal from containment	Containment pressure (1)		Sources contributing to inadequate heat removal follow in this table.
109 Reactor power high	112 Neutron absorbers not present in ECC water	Boric Acid Charging flow (2)	PCS Boron concentration (3)	Both flow and concentration should be measured; failure of this system may be addressed by pump/valve status diagnostics.
	113 Failure to scram	Control rod position (1)		
114 Inadequate cooling of containment spray	115 Heat exchanger fouling	None		Difficult to instrument, long term problem anticipated by regular inspection.
116 Inadequate CS heat exchanger coolant flow	117 Flow blockage	Component cooling water flow (2)		Valve position and valve status diagnostics would be useful.
	118 Loss of CS H_x pump	None		Pump status diagnostics would be useful.
	119 Inadequate coolant supply	None		Valve line up and supply status.

Event	Cause	Specific Measurement Required by Regulatory Guide 1.97 (Category)	Possible Signal Required by Regulatory Guide 1.97 (Category)	Comments
120 Failure of containment spray	122 Flow blockage	Containment spray flow (2)		Valve position and valve status diagnostics would be useful.
	123 Loss of CSR system pump	Containment spray flow (2)		Pump status diagnostics are applicable.
	124 Inadequate containment sump water level	Containment sump water level (1)		Inadequate level may result in damage to CSR pump.
124 Inadequate containment sump water level	126 Flow blockage	Flow in HPIS (2) Flow in LPIS (2)		Difficult to instrument, valve line up would be useful.
	127 Loss of HPIS or LPIS pump	Flow in HPIS (2) Flow in LPIS (2)		Pump status diagnostics are applicable.
	128 Inadequate level maintained in RWST	RWST level (2)		
121 Containment heat exchanger system malfunction	129 Inadequate primary flow	Flow in LPIS (2)		Events 124, 132 and 133 may lead to this condition, pump status and valve status diagnostics are applicable.
	130 Inadequate secondary flow	Component cooling water flow to ESF system (2)		Events 134, 135 and 136 may lead to this condition, pump status and valve status diagnostics are applicable.
	131 Fouling of heat exchanger	None		Long term problem can be anticipated by regular inspection.

TABLE 11. EVENTS RELATED TO CONTAINMENT INTEGRITY IN A BWR

Event	Cause	Specific Measurement Required by Regulatory Guide 1.97 (Category)	Possible Signal Required by Regulatory Guide 1.97 (Category)	Comments
210 Breach of high energy piping in containment	Unspecified	None	Primary containment area radiation (3)	Not directly measurable. Measure pressure or liquid volume change, or use acoustic leak detection methods.
251 Improper water level	Unspecified	None	None	
224 RHR system failure	Events 210 or 251	RHR system flow (2) RHR heat exchanger outlet temperature (2)	None	Detectable through interpretation of temperature measurements.
250 Loss of containment spray	Unspecified	None	None	Detectable for flow measurements, except for a pipe break downstream of measurement location. Possibly detectable by containment temperature measurements.
223 Inadequate heat removal from containment	Events 210, 224, 250	None	None	Detectable by simple temperature measurements.
225 Vacuum breaker system failure	Unspecified	None	None	Detectable by pressure measurements.
222 Ventilation system failure	Unspecified	Emergency ventilation damper open or closed (2)	None	Detectable by temperature measurements.
221 Hydrogen explosion	Excessive hydrogen accumulation	Hydrogen concentration (1)	None	Hydrogen concentration is directly measurable.
220 Atmosphere dilution system failure	Unspecified	None	Hydrogen concentation (1) Containment effluent radioactivity (3)	Indicated by excessive accumulation of hydrogen or other gases
203 Containment pressure high	Events 220-223, 225, 210	Containment pressure (1)	None	Easily measured directly.
230 Isolation valve failure	Unspecified	Valve closed or not closed (1)	None	Some failure modes, such as small seat or seal leaks, are difficult to detect.
231 Seal failure	Unspecified	None	None	Probably detectable through scheduled inspections.

TABLE 11. (continued)

Event	Cause	Specific Measurement Required by Regulatory Guide 1.97 (Category)	Possible Signal Required by Regulatory Guide 1.97 (Category)	Comments
204 Containment isolation failure	Events 230 and 231	None	Airborne radioactive materials measurements (2)	Not directly detectable.
205 External forces	240 Natural disasters (floods, etc)	None	None	Partly predictable
	241 Man-caused accidents (airplane crashes, etc)	None	None	Usually not predictable.
202 Material defects	Unspecified	None	None	Usually detectable through quality control and inspection.

TABLE 12. ANTICIPATORY MEASUREMENTS

Reactor Power	NSAC	RG 1.97	EG&G	Status
Control rod position	X		X	1
Control rod velocity			X	2
Neutron flux	X	X	X	1
Boron concentration	X	X	X	1
Cold leg temperature		X	X	1
Instrument integrity			X	5
Core Heat Removal				
RCS pressure	X	X		
Reactor coolant level	X	X	X	3
Subcooling	X	X	X	1
Valve position		X		
Valve status			X	5
Pressurizer level	X	X	X	1
Core exit temperature	X	X	X	1
Hot leg temperature	X	X	X	1
Cold leg temperature	X	X	X	1
PCS flow rate	X	X	X	1
Pump P			X	1
Pump current		X	X	1
Pump status			X	5
Instrument integrity			X	5
Secondary Side Heat Removal				
Main feedwater flow	X	X	X	1
Emergency feedwater flow	X	X	X	1
Steam generator level	X	X	X	1
Steam generator pressure	X	X	X	1
Safety/relief valve position		X		
Safety/relief valve status			X	5
Main steam flow valve position		X		
Main steam flow valve status			X	5
Instrument integrity			X	5

TABLE 12. (continued)

	NSAC	RG 1.97	EG&G	Status
Primary Pressure Boundary Integrity				
RCS pressure	X	X		
Pump seal flow (inlet and outlet)	X		X	1
Seal temperature			X	1
Relief valve position		X		
Relief valve status			X	5
Vibration surveillance			X	5
Pump status			X	5
Instrument integrity			X	5
Containment Integrity				
Containment pressure	X	X		
Containment H_2 concentration	X	X	X	1
Boric acid charging flow	X	X	X	1
PCS boron concentration	X	X	X	1
Control rod position	X	X	X	1
Component cooling water flow	X	X		
Containment spray flow	X	X		
Containment sump water level	X			
Flow in HPIS	X	X		
Flow in LPIS	X	X		
RWST level	X	X		
Valve status diagnostics	X		X	5
Pump status diagnostics	X		X	5
Instrument integrity			X	5

TABLE 13. RECOMMENDED DIAGNOSTIC INSTRUMENT PERFORMANCE CHARACTERISTICS

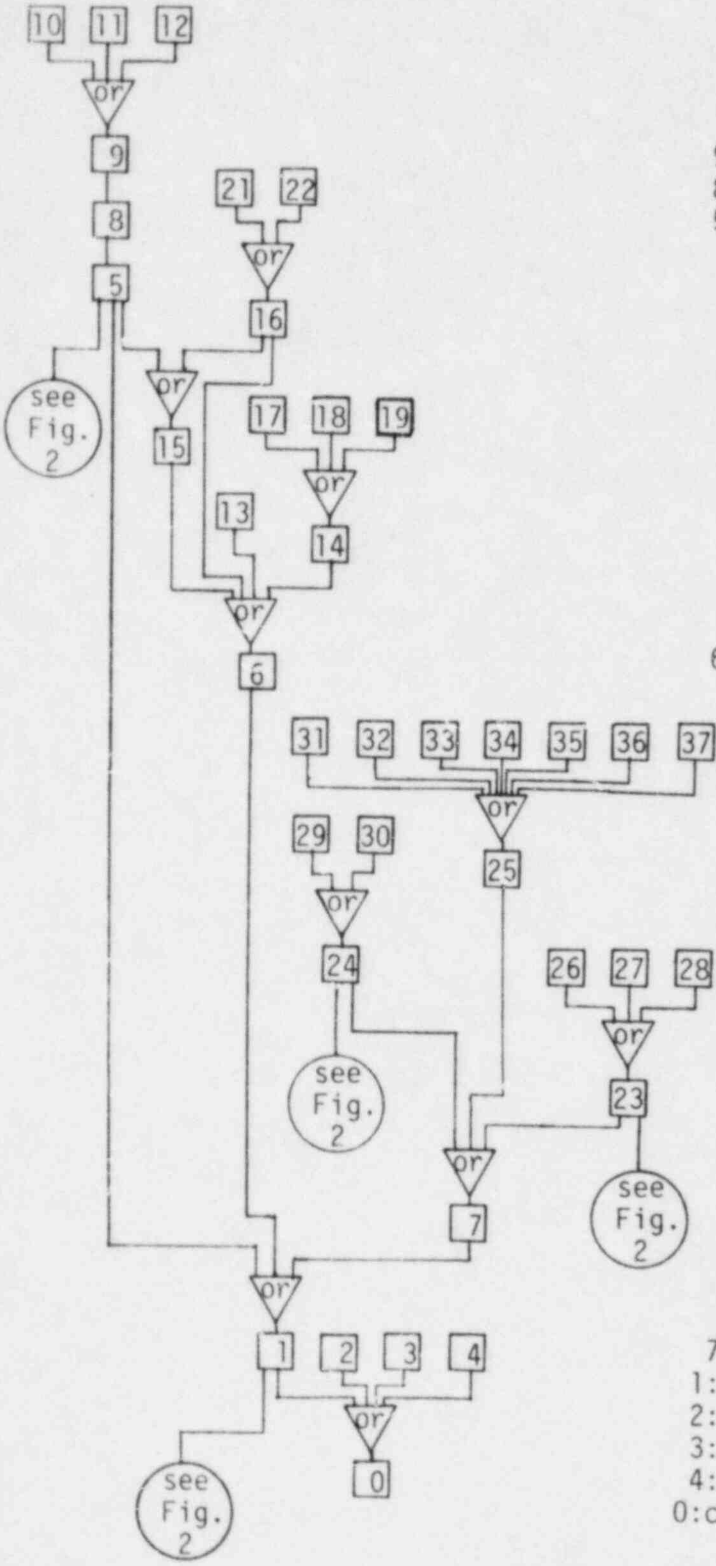
Measurement	Range	Comments
Reactor Power		
Control rod velocity	0-110% design	Indicate uncontrolled withdrawal
Neutron flux	Source intermediate power	Indicates reactivity and heat generation
Boron concentration	0-2700 ppm	Indicates shutdown margin
Cold leg temperature	50°F to 750°F	
Instrument integrity	Instrument specific	Anticipation of failure
Core Heat Removal		
Reactor coolant level	0-100%	Indication of adequate core cooling
Subcooling	200°F subcooled to 35°F superhot	Indicates margin to boil
Valve status	Valve specific	Anticipation of failure
Pressurizer level	0-100%	Indicates loss of coolant or presence of gas
Core exit temperature	150-2800°F	Indicates possible local blockage
Hot leg temperature	150-2800°F	Indicates possible core overheat
PCS flow rate	-10% to 110%	Indicates potential effectiveness of core cooling
Pump ΔP	0-110% design	For pump diagnostic and cavitation

TABLE 13. (continued)

Measurement	Range	Comments
Core Heat Removal	(continued)	
Pump current	0-100% design	For pump diagnostic and cavitation
Pump status	Pump specific	Anticipation of failure
Instrument integrity	Instrument specific	Anticipation of failure
Secondary Side Heat Removal		
Main feedwater flow	0-110% design	Indicates heat removal
Emergency feedwater flow	0-110% design	Indicates heat removal
Steam generator level	0-100% design	Indicates heat removal
Steam generator pressure	0-4000 psig	Indicates heat removal
Safety/relief valve status	Valve specific	Anticipation of failure
Main steam line flow valve status	Valve specific	Anticipation of failure
Instrument integrity	Instrument specific	Anticipation of failure
Primary Pressure Boundary Integrity		
Pump seal flow (inlet/outlet)	0-110% design	Indicates seal integrity
Seal temperature	150-750°F	Anticipation of failure
Relief valve status	Valve specific	Anticipation of failure
Vibration surveillance	Location specific	Anticipation of failure
Instrument integrity	Instrument specific	Anticipation of failure

TABLE 13. (continued)

Measurement	Range	Comments
Containment Integrity		
Boric acid charging flow	0-110% design	Indicates ability to shutdown plant
PCS boron concentration	0-2700 ppm	Indicates shutdown margin
Control rod position	0-100%	Indicates scram
Various valve position status	Valve specific	Anticipation of failure
Various pump status	Pump specific	Anticipation of failure



12: reactivity insertion by feedback
11: reactivity insertion due to fuelling
10: reactivity insertion due to control rod/boron dilution
9: positive reactivity insertion
8: high neutron power
5: reactor power high

22: loss of primary coolant pump
21: flow path blockage
16: low flow or loss of primary flow
15: change in heat transfer coefficient

19: stuck open relief or bypass valves
18: spurious opening of safety/relief valves or bypass valves
17: primary coolant piping break; small break or LOCA
14: loss of primary coolant

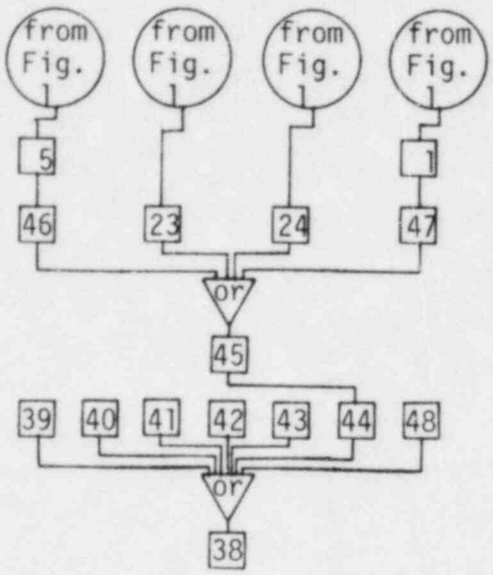
13: crud deposition on fuel
6: inadequate heat removal by coolant

37: steam out flow more than feed flow, feed water control malfunction
36: steam line rupture
35: stuck open relief valve or turbine bypass valve
34: spurious opening of steam generator relief or turbine bypass valve
33: rupture of feedwater line
32: stuck closed feed water valve
31: loss of feed pumps
25: loss of secondary coolant

30: flow instability in secondary coolant
29: steam generator tube fouling
24: inadequate heat transfer from primary to secondary coolant

28: generator load rejection
27: turbine trip
26: steam generator isolation from turbine
23: secondary coolant temperature high
7: reactor inlet primary coolant temp. high
1: clad temperature high
2: corrosion by reactor coolant or fission gas
3: clad mechanical defect
4: clad fatigue and creep
0: clad failure

Figure 1: Breach of Cladding Event Tree.



5:reactor power high
46:high energy transfer from fuel to coolant

1:fuel clad temperature high
47:additional energy release by metal-water reaction

24:inadequate heat removal from primary to secondary

23:secondary coolant temperature high

45:increase in primary coolant energy

39:material welding defect

40:fatigue, creep, or corrosion

41:external events: earthquake, etc.

42:vibration

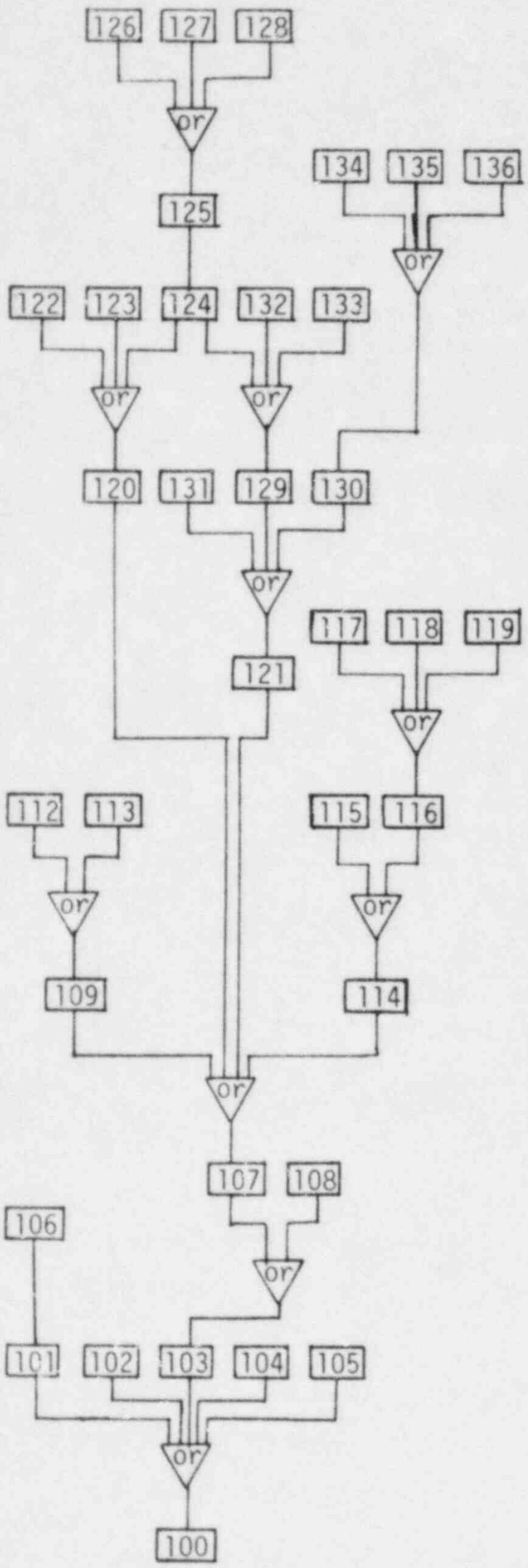
43:pump or valve seal failure

44:primary coolant pressure high

48:PRV, PORV, or LPIS check valve failure

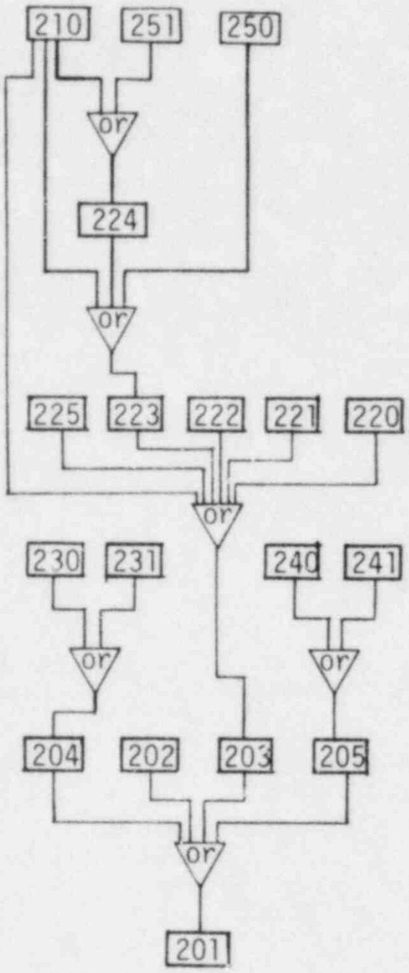
38:breach of primary coolant boundary

Figure 2: Breach of Primary Coolant Boundary Event Tree.



128:inadequate level in RWST
127:loss of HPIS or LPIS pump
126:flow blockage
125:inadequate ECC injection
124:inadequate containment sump water level
123:loss of CSR system pump
122:flow blockage
120:containment spray failure
136:inadequate coolant supply
135:loss of pumps
134:flow blockage
130:inadequate secondary flow
133:flow blockage
132:loss of pumps
129:inadequate primary flow (LPIS)
131:fouling of heat exchanger
121:containment heat exchange system malfunction
119:inadequate coolant supply
118:loss of pumps
117:flow blockage
116:inadequate CS heat exchanger coolant flow
115:heat exchanger fouling
114:inadequate cooling of containment spray
113:plant did not scram
112:neutron absorbers not present in ECC
109:reactor power high
107:inadequate heat removal from containment
108:hydrogen burn or explosion
103:containment pressure high
106:failure of LPIS isloation valves
101:breach of LPIS system
102:external event (projectile, earthquake, etc.)
104:material defect
105:failure of feedthrough seal
100:breach of containment

Figure 3: Breach of Containment Event Tree for PWRs.



210:breach of high energy piping in containment
251:improper water level
224:RHR system failure
250:loss of containment spray
223:inadequate heat removal from containment
225:vacuum breaker system failure
222:ventilation system failure
221:hydrogen explosion
220:atmosphere dilution system failure
203:containment pressure high
230:isolation valve failure
231:seal failure
204:containment isolation failure
240:earthquakes, tornadoes, floods, etc.
241:airplanes, missiles, projectiles, etc.
205:external forces
202:material defect
201:breach of containment

Figure 4: Breach of Containment Event Tree for BWRs.