Attachment 1

ABNORMAL TRANSIENT OPERATING GUIDELINES

(ATOG)

PROGRAM DESCRIPTION

PREPARED FOR

B&W OWNERS GROUP

OPERATOR SUPPORT COMMITTEE

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Babcock & Wilcox
a McDermott company

ABSTRACT

This report documents the evolution of the symptom-oriented procedure concept employed by the Abnormal Transient Operating Guidelines and describes the development effort involved in the preparation of those guidelines. It also discusses the usage of ATOG and the support bases. This report is provided in response to item I.C.1 of NUREG-0737, "Guidance for the Evaluation and Development of Procedures for Transients and Accidents".

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1.0 INTRODUCTION

The Nuclear Industry's perspective of emergency operation has changed considerably as a result of the Three Mile Island accident on March 28, 1979. Numerous innovative changes have taken place since TMI-2. The Abnormal Transient Operating Guidelines (ATOG) (reference 5.1) and associated display technique is but one of the methods B&W Owners have pursued to improve plant operation and it directly addresses the two major factors that caused the shift in perspective: the combination of multiple failures and incorrect interpretation of information. This report describes the development, usage, and bases for ATOG.

Section 2.0 of this report is a synopsis of the lessons learned from the TMI-2 event as they were set forth by the NRC in NUREG-0578 (reference 5.4) and how they led to the development of ATOG. The limitations of previous analyses and event-oriented procedures with respect to complex transients are discussed and compared with the improvements inherent in the ATOG concept.

Instructions on the use of ATOG are provided in Section 3.0. This section describes the use of the procedural guidelines in Part I of ATOG and the ATOG display format, and how Part II relates to the usage of Part I.

Section 4.0 of this report provides the ATOG bases. The various tasks that were involved in the guideline development are described in detail and the philosophy for coverage of equipment availability, effects of natural phenomena, and consideration of multiple failures are discussed.

This section also provides a point-by-point response to item I.C.1 of NUREG-0737 (reference 5.2).

2.0 LESSONS LEARNED FROM TMI-2

A reevaluation by the NRC of the concept for handling emergency operations following the TMI-2 accident concluded that some basic deficiencies existed in the coverage provided. These deficiencies can be generally categorized as analytical, procedural, and design. Sections 2.1, 2.2, and 2.3 provide discussions of these concerns as identified in NUREG-0578.

2.1 Analyses

NUREG-0578 pointed out that the basic industry philosophy behind plant and equipment design had been to account for two general cases: normal plant operations and worst case design bases accidents. Analyses performed to support plant design were thus structured around these two general cases. The design bases accident analyses also included required conservatisms that would not exist in an actual accident (e.g., the use of 120% of maximum decay heat).

Regulatory requirements dictate that safety systems be designed and sized to mitigate design bases accidents even when degraded by a single failure. The general industry belief was that equipment sized to mitigate the worst case accidents could easily handle events on a smaller scale. However, it has since become evident that systems designed for the large design bases event could, in fact, result in different problems when smaller scale transients occur. For example, the emergency feedwater (EFW) systems are

typically sized to provide sufficient feed flow to remove maximum decay heat even when degraded by a single failure (e.g., one EFW pump fails to start). Therefore, when no failures occur the EFW system can deliver significantly more feed flow than required. This can result in excessive cooling of the primary system, especially at lower decay heat levels. Thus, the EFW system was designed to prevent overheating when a loss of main feedwater occurred yet it can, when worst case conditions don't exist, cause overcooling.

Another identified concern with the historical two-pronged analysis approach is that smaller scale events can lead to conditions that would not exist in the larger design bases event, and therefore were not previously identified nor accounted for in design or procedures. An example is the evolution of the Small Break Operating Guidelines (reference 5.3) which stress the importance of the steam generators for heat removal and the necessity to trip the RC pumps for small break LOCAs. Neither of these were significant factors in the design basis large LOCA previously analyzed.

Automatic system actuation setpoints were also based on the design bases events thus, for small transients, operator recognition and mitigation are required to maintain safe conditions. However, since some of the emergency procedures available to the operator were based on FSAR (design bases) events, they did not always provide the necessary guidance for actual transients. For example, as stated in NUREG-0578, the TMI-2 procedure for loss of feedwater was

based on the FSAR analysis. This analysis, for conservatism, assumed the PORV did not open in order to determine maximum RCS pressure. Thus, the procedure did not alert the operator to the fact the PORV would open nor did it address the importance of verifying subsequent closure of the PORV. In addition, procedures did not always exist for the smaller scale event because it was unanalyzed and previously considered covered by the procedure for the large scale event. As an example, the procedure for tube rupture was typically based on a large double-ended break of a steam generator tube. Some of the actions specified (e.g., trip the reactor) are not desirable actions for small scale events where the plant can be shutdown without lifting steam safety valves. However, it was the only related procedure available for the operator to follow.

These concerns expressed in NUREG-0578 all stem from the previously accepted practice of analyzing only for normal plant operations and design bases accidents. NUREG-0578 states that a real need exists for realistic analyses to form a basis for guidance in the mitigation of abnormal transients. When one considers that the small scale event has a much higher probability of occurrence than the design bases event, the potential seriousness of this misemphasis becomes apparent.

2.2 Procedures

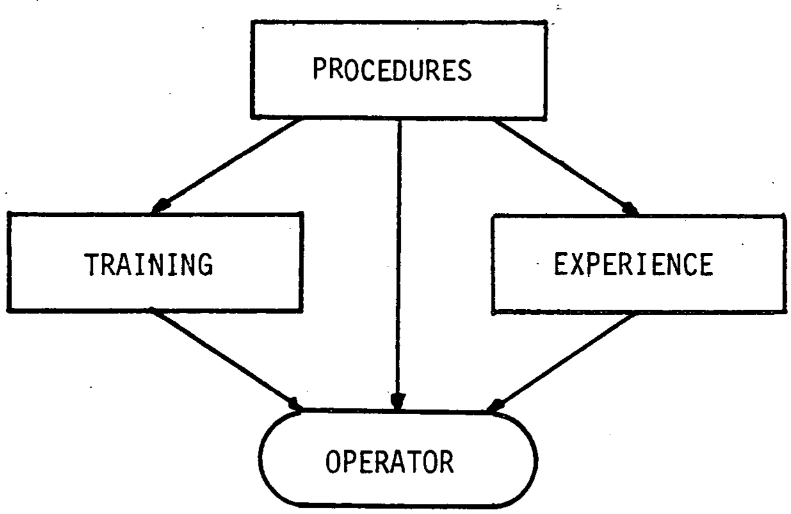
The traditional approach to transient and accident control has been to develop many "emergency" procedures, each based on a postulated

event such as loss of main feedwater. The operator is then required to study this event and memorize its symptoms and immediate actions. If a loss of feedwater occurs, he is expected to recognize it, perform the appropriate immediate actions, and then use the event-oriented loss of feedwater procedure for determining follow-up actions. This approach, while adequate, has several areas which can be improved:

1. At time zero, the operator must correctly diagnose the initiating event. He does this mentally, based on training and prior experience. After taking several actions, depending on this instant evaluation, he then refers to the event-oriented procedure that fits his diagnosis. If he were to treat a small steam line break inside the reactor building, for example, but actually had a small loss of coolant accident (LOCA) inside the building, he would be tracking through the wrong procedure. He would eventually recognize this misinterpretation. However, by then he would be well into the transient and possibly confused.
2. Procedures must be written to cover every conceivable initiating event. If the operator correctly diagnoses an initiating event but no procedure is available that covers that event, then his actions will be based only on experience.
3. If more than one event contributes to the transient, the operator will find himself working with two or more procedures at the same time. For instance, if a main steam safety valve failed to reseat following a loss of main feedwater, the operator would have to use the loss of feedwater procedure and

small steam line break procedure (if available). These procedures may conflict and he would have to decide a priority between them - with no convenient method of shifting between the two procedures. Writing a procedure to combine these two events is possible. However, the number of possible failure combinations makes this approach impractical. Even if writing all the appropriate procedures were attempted, the resulting quantity would make it more difficult for the operator to select the correct procedure.

These items have an impact on operator effectiveness beyond just not providing sufficient guidance during some transients and accidents. They affect all facets of the operator's development. The operator relies on his procedures, training, and experience in mitigating transients. In actuality, both his training and eventually his experience are developed from the use of the procedures as shown:



Thus, good procedures are vital to the maintenance of safe plant conditions. It was evident that a new approach to procedure development and writing was in order.

2.3 Design

Another area noted for improvement in NUREG-0578 is in control room layout and information display methodology. While functional grouping of controls and instrumentation had been considered in control room designs, human factors engineering, per se, had not been a primary concern. The operators had access to all the required controls and data, but changes could be made to better facilitate their use. A prime example is display information for reactor coolant status. The operator was provided with all the necessary information but in a discrete format, i.e., separate displays for temperature and pressure. Therefore, he was required to mentally correlate their relationship with each other and with appropriate pressure-temperature limits (margin to saturation, NDT, NPSH, etc.). Display methods that correlate the information for the operator would provide a distinct improvement, especially in emergency situations involving higher stress and requiring quick operator response times.

The Lessons Learned Task Force identified these concerns, among others, in NUREG-0578 which can be summarized as follows:

1. The industry had not fully utilized its combined analytical capabilities in past development of emergency procedures nor in training of the operations staff.

2. Realistic analyses (less conservatism) should be used in contrast to previous analyses which were primarily intended for design bases events. Realistic analyses can identify proper and improper operator actions associated with important safety concerns such as prevention of core uncovery, establishing natural circulation, prevention of event degradation to more serious accidents, etc. In addition, results of realistic analyses can provide needed training material to promote operator understanding and familiarity with plant response during abnormal conditions.
3. There is a need to provide operator guidance for events and conditions that previously were not foreseen, analyzed, or prepared for. Satisfying this need requires the development of a procedural format that transcends the limitations of the event-oriented procedure concept.
4. There is a need for improvement in the type, quantity, and method of displays provided to the operator.

To address these areas, it is necessary to step back from the traditional approach and examine what the operator is attempting to do during post trip abnormal transient control. He can best protect the health and safety of the public by guarding the integrity of the core. To do this he must ensure the continuous removal of decay heat from the fission products to the appropriate heat sink. By adjusting the priorities and concentrating efforts on maintaining proper heat transfer along this path, he can protect

the core and minimize radioactive release. To give the operator this capability, a concept of symptom-oriented (as opposed to event-oriented) procedures was investigated. The symptoms are based on upsets in heat transfer from the core to the coolant and from the coolant to the steam generators. The symptom-oriented procedures thus focus on core cooling first and on event identification second. The result of this investigation is the Abnormal Transient Operating Guidelines (ATOG).

2.4 Development of the ATOG Concept

2.4.1 Expected Plant Response

To produce a symptom-oriented procedure, B&W developed a thorough understanding of expected plant responses during many varied abnormal transients. These transients included the classic singular initiating events as well as additional single and multiple component failures. The procedure was developed through the following steps:

1. Existing plant casualty procedures were reviewed for common symptoms. Few single alarms or parameters were found to uniquely identify a transient. Similarly, some parameters were common to all transients. Because the plant must be operated within Technical Specification limits (i.e., limiting safety system settings and limiting conditions for operation), reactor trip and forced shutdown are used for entry into the ATOG procedure. If the reactor trips a limiting safety system setpoint has

been challenged and if a limiting condition for operation is exceeded a forced shutdown is required. Thus the ATOG procedure is followed anytime there is a regulatory concern of the magnitude that would exceed Technical Specifications.

2. Event trees for various initiating events (discussed in more detail in Section 4.0) and consequential failures were developed. These included various multiple failures (including operator error), and therefore covered a large number of possible scenarios. Event trees were studied to find repetitive patterns and common end points. The study showed that, although many failures can occur, the symptoms of unbalanced heat transfer that result from these failures followed a few common patterns or trends.

3. Actual operating transients were investigated, again looking for patterns. This time the emphasis was placed on parameter trends and the times available for operator actions.

4. Where necessary, computer simulations were run to complete the baseline and fill in gaps in understanding plant response. Because the output was intended for use in developing operating guidelines, realistic input was used (as opposed to bounding safety analysis assumptions).

This investigation's conclusion was that the operator can track the removal of decay heat from the core to the ultimate heat sink by monitoring just a few symptoms which reflect the "health" of the thermodynamic process around the reactor coolant system and its coupling to the secondary side.

2.4.2 Symptoms Identified

The three symptoms of primary interest to the pressurized water reactor (PWR) operator are adequate subcooling of the primary system inventory, inadequate primary-to-secondary heat transfer, and excessive primary-to-secondary heat transfer. These symptoms are important for the following reasons:

1. Adequate primary inventory subcooling:
   If the operator knows the primary fluid is in a liquid state, he is assured that it is available and capable of removing heat from the core and transferring it to the steam generators. If subcooling is lost, these capabilities are in doubt, and he is therefore directed to make every effort to regain subcooling.
2. Inadequate primary-to-secondary heat transfer:
   This symptom addresses the heat transfer coupling across the steam generators. It describes the ability of the system to keep the flow of energy moving from the reactor coolant system to the ultimate heat sink. The operator monitors the relationship between the reactor

coolant cold leg temperature and steam generator secondary side saturation temperature. Following a reactor trip, these two values should be nearly equal under good heat transfer conditions. If this coupling is broken, the procedure outlines appropriate corrective actions to restore it.

3. Excessive primary-to-secondary heat transfer:

   In this case, the symptom is indicative of a secondary side malfunction (e.g., loss of steam pressure control or steam generator overfill). Cold leg temperatures and SG saturation temperatures will be nearly equal but will be decreasing below normal post-trip values. The heat transfer is again unbalanced and the operator's attention is directed toward generic actions to restore this balance.

By tracking these basic symptoms the operator can quickly focus on problems without checking a large number of parameters. At the same time, by their nature the symptoms allow rapid elimination of problem sources and continue to emphasize core protection. Additionally, the symptoms are so basic that the procedure inherently covers any initiating event that would deter core cooling. This is true because initiating events cause (or are caused by) equipment failures, and equipment failures affect these symptoms. As the operator follows the procedure to treat the symptom he will often identify and correct the cause, but it is not necessary to do so to maintain safe plant conditions.

2.4.3 ATOG Display

The information required to identify and track these symptoms is already available in power plant control rooms. The problem is how these variables can best be displayed to give the operator a simple and logical method of monitoring the symptoms of interest. The solution developed in ATOG is shown in Figure 1 and is basically a pressure-temperature (P-T) display with a saturation curve included. The area above and to the left of this curve is the subcooled region. The area below and to the right is the superheated region. Reactor coolant system hot leg temperature (Thot) and cold leg temperature (Tcold) are input to this display and plotted against reactor coolant system pressure. Steam generator pressure is also input. The saturation temperature for this input pressure is displayed as a vertical line. The subcooled margin accounts for potential instrumentation inaccuracies with the objective of assuring subcooling above that line.

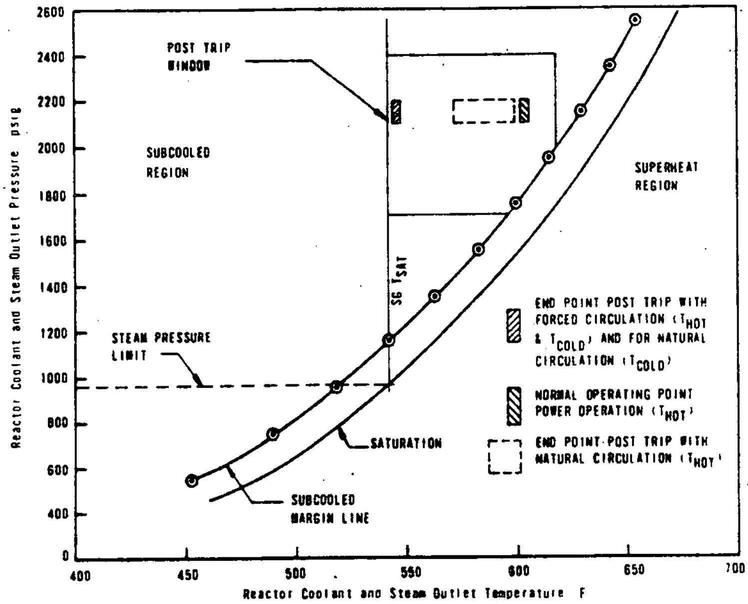


Figure 1 ATOG DISPLAY

A typical plant response to a reactor trip is shown in Figure 2. For simplicity, only reactor coolant hot leg temperature is plotted.

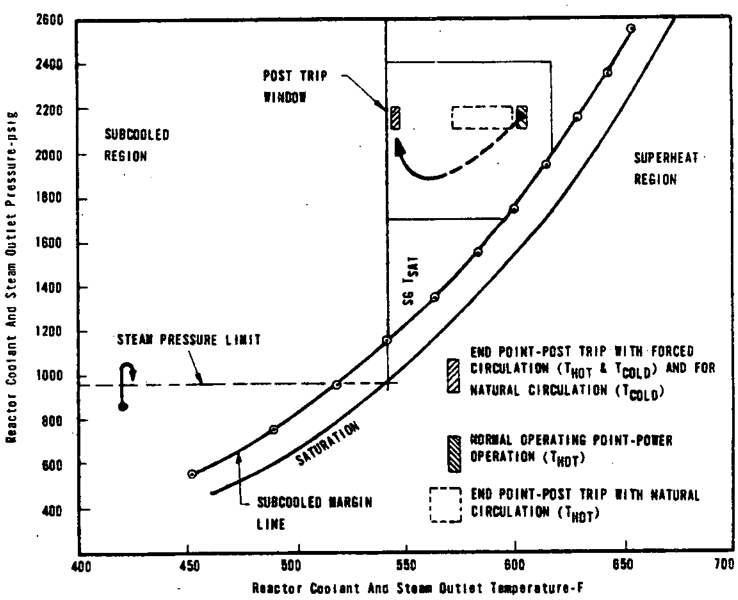


Figure 2 TYPICAL PLANT RESPONSE FOLLOWING TRIP

With the reactor coolant pumps running (forced circulation), and the comparatively small amount of energy being added to the coolant by decay heat and the RCP's, the cold leg temperature is also expected to settle out close to this hot leg temperature. Additionally, because the ΔT across the steam generator tubes is small, both of these temperatures should approach the saturation temperature of the secondary side of the steam generator (SG Tsat). The figure also shows steam pressure moving from its pre-trip value up to the steam safety valve setpoint and back to its post-trip value. As long as Thot, Tcold, and SG Tsat remain within a "post-trip window" the plant is responding normally.

With this type of display, the symptoms of interest are highlighted and brought into focus for the operator. Consider the examples in Figures 3A-C on the following pages:

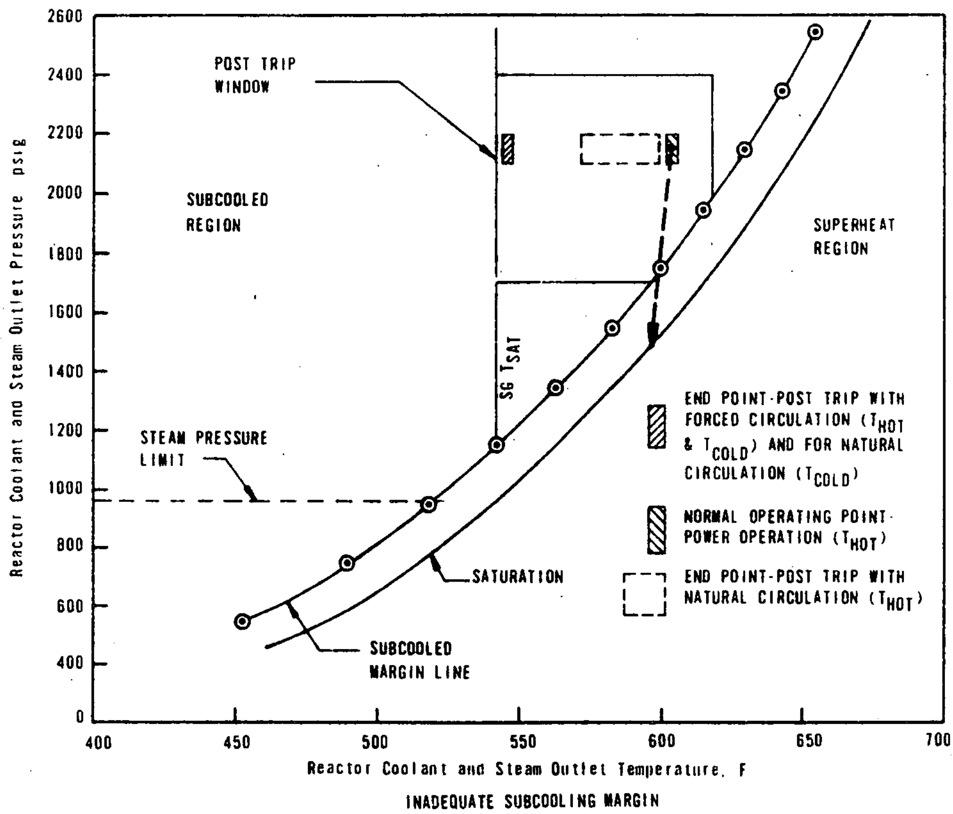


Figure 3A <u>Inadequate subcooling margin</u>:

Thot is not progressing toward its target value; in fact, it has rapidly dropped through the subcooled margin line. This condition is diagnosed as loss of adequate primary inventory subcooling, or simply "inadequate subcooling margin", and the procedure is written with directions to take care of inadequate subcooling margin.

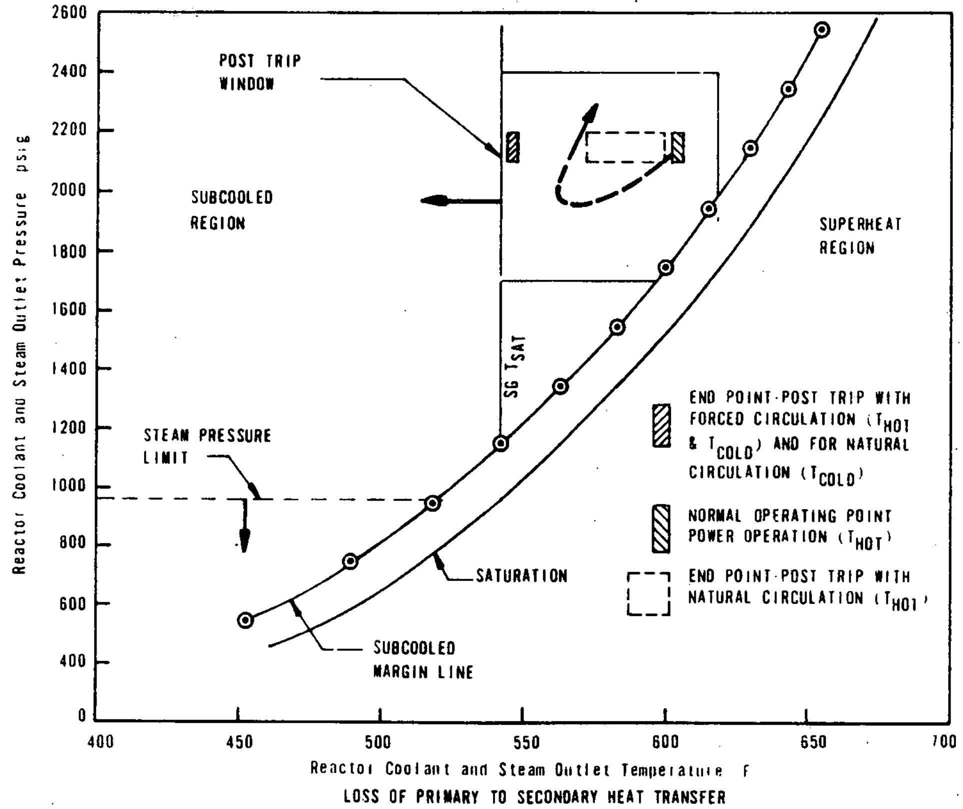


Figure 3B Loss of primary-to-secondary heat transfer:

Thot is increasing as SG Tsat is decreasing. The ΔT between the two is growing larger. The secondary is no longer removing heat and has lost coupling with the primary. This condition is diagnosed and treated as loss of (inadequate) primary-to-secondary heat transfer.

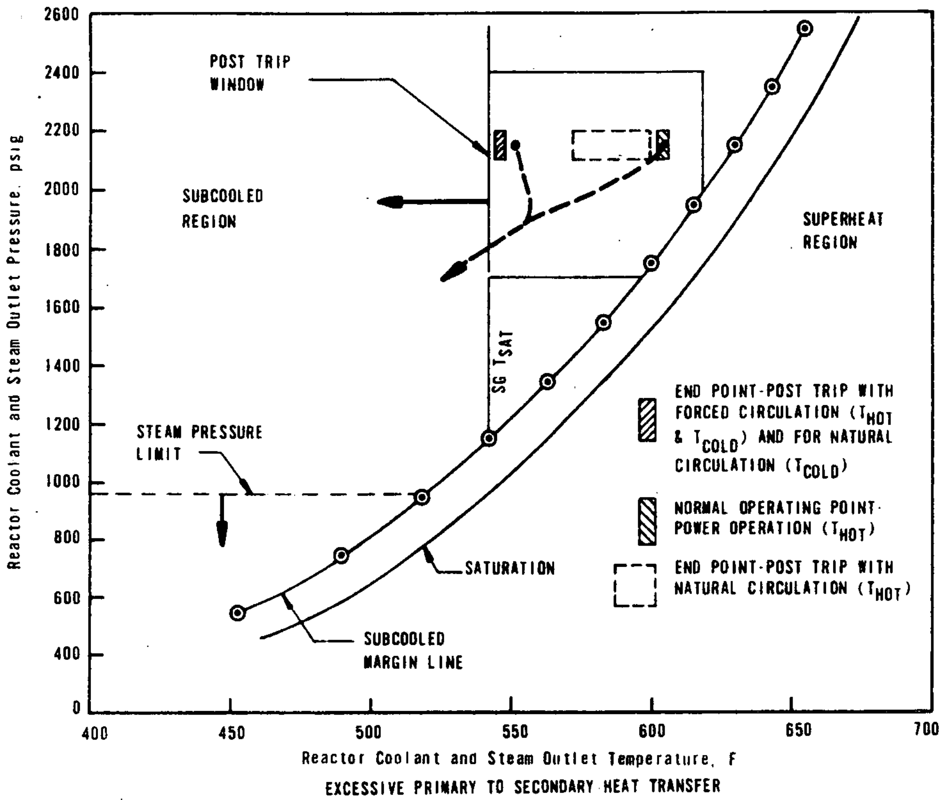


Figure 3C Excessive primary-to-secondary heat transfer:

SG Tsat has decreased below its established limit. Thot and Tcold have reached equal values but both have gone out of the post-trip window following SG Tsat. This condition is diagnosed and treated as excessive primary-to-secondary heat transfer.

Combinations of these symptoms are also easily recognized. This is shown by the examples in Figures 4A-D which were taken from the first twenty minutes of the TMI-2 event.

0 To 5 Minutes

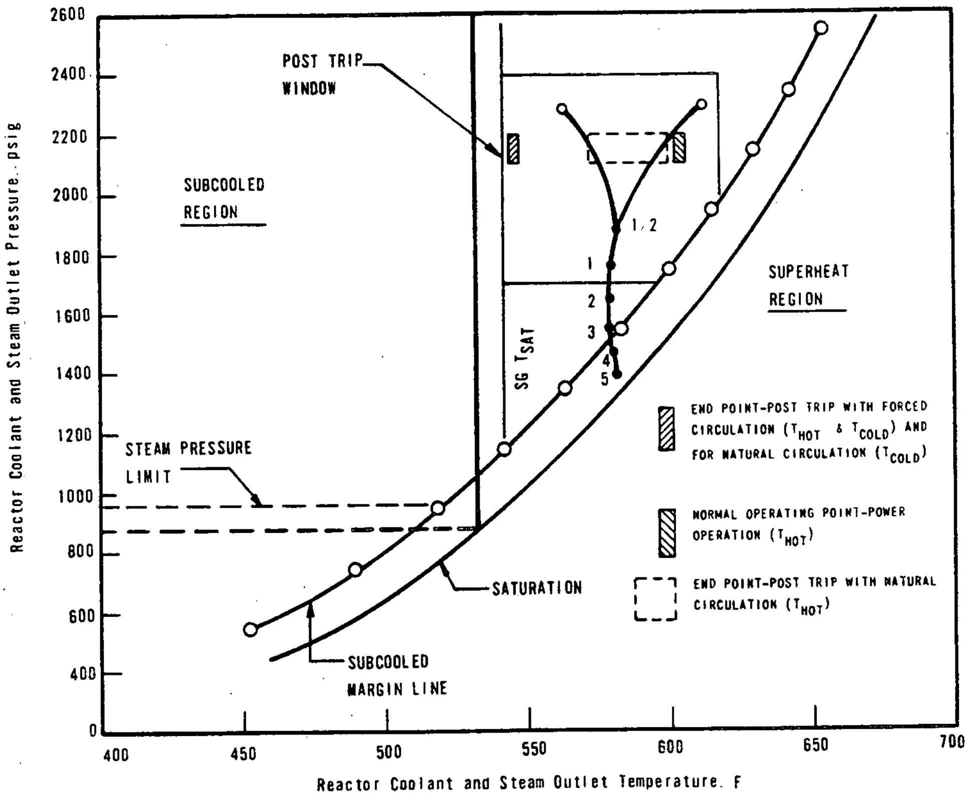


Figure 4A 0 to 5 minutes:

At time zero the reactor has tripped on high pressure due to a loss of feedwater. At 1/2 minute Thot and Tcold are essentially the same temperature. At 2 1/2 minutes the ESFAS pressure setpoint is reached and high pressure injection (HPI) is automatically started. At 3 1/2 minutes subcooling margin is lost, and at 4 1/2 minutes the operator stops HPI. By the time 5 minutes have elapsed the RCS is beginning to heat up. Secondary pressure and temperature are below limits. The primary-to-secondary ΔT is $\sim$50F.

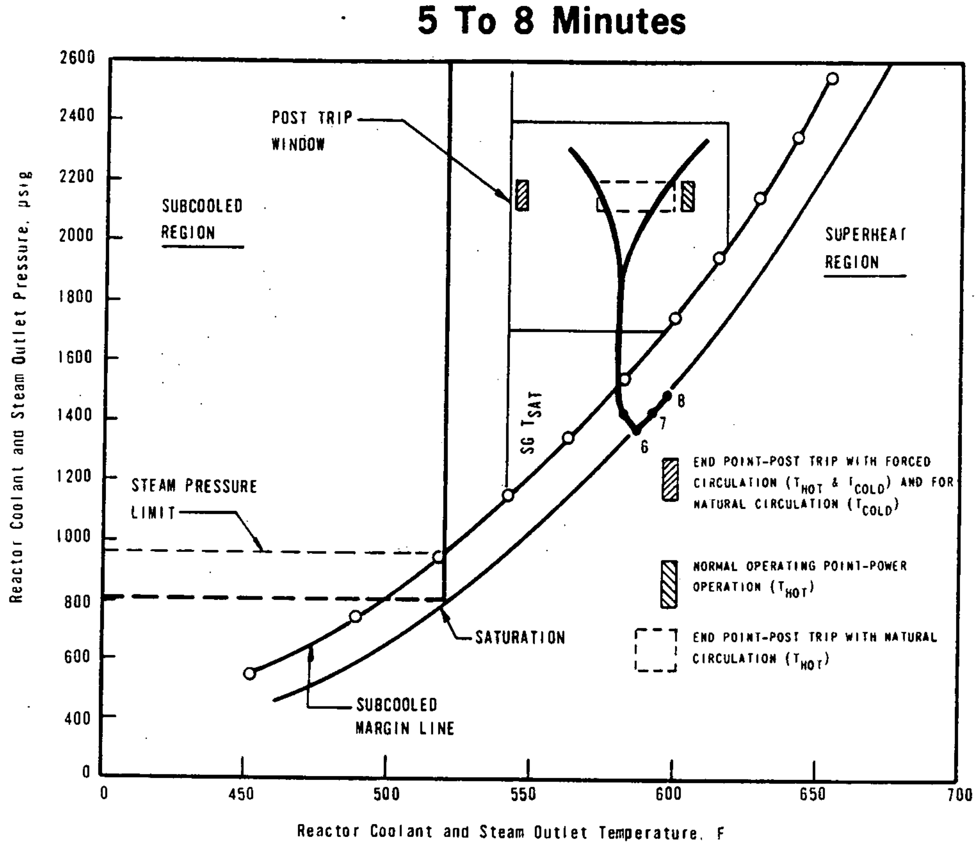


Figure 4B 5 to 8 minutes:

The primary continues to heat up along the saturation line while secondary temperature and pressure drop. At 8 minutes the primary-to-secondary ΔT is $\sim$80F. Also, auxiliary feedwater is first directed to the steam generators.

8 To 15 Minutes

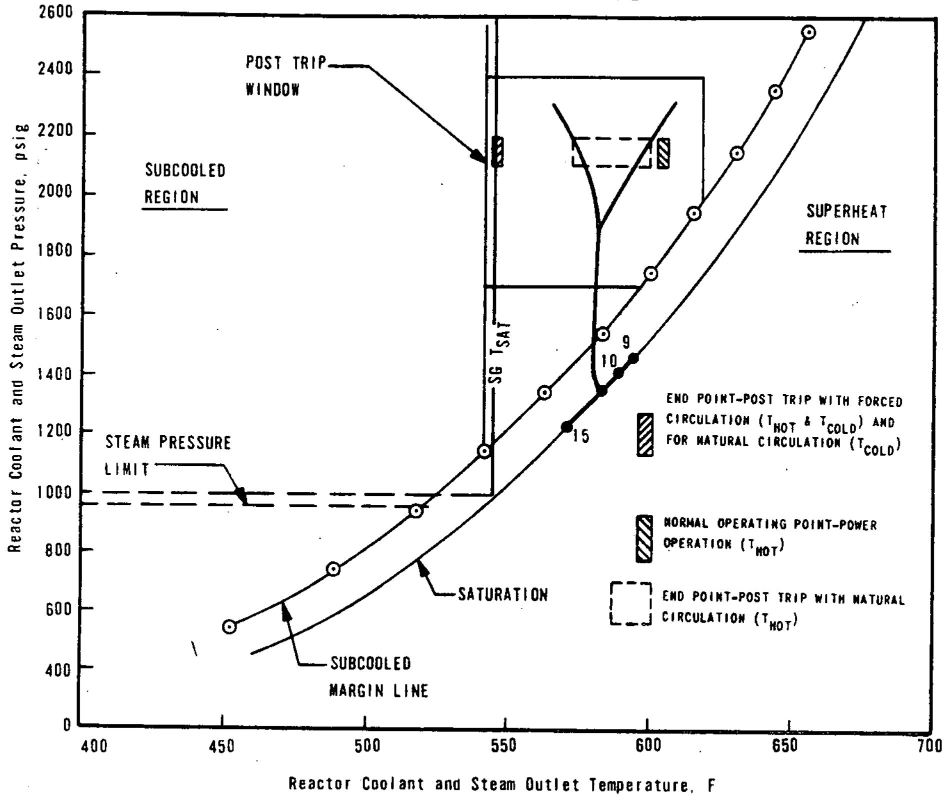


Figure 4C 8 to 15 minutes:

Steam pressure and temperature have recovered to their normal post-trip values. A substantial cooling of the primary is also in progress.

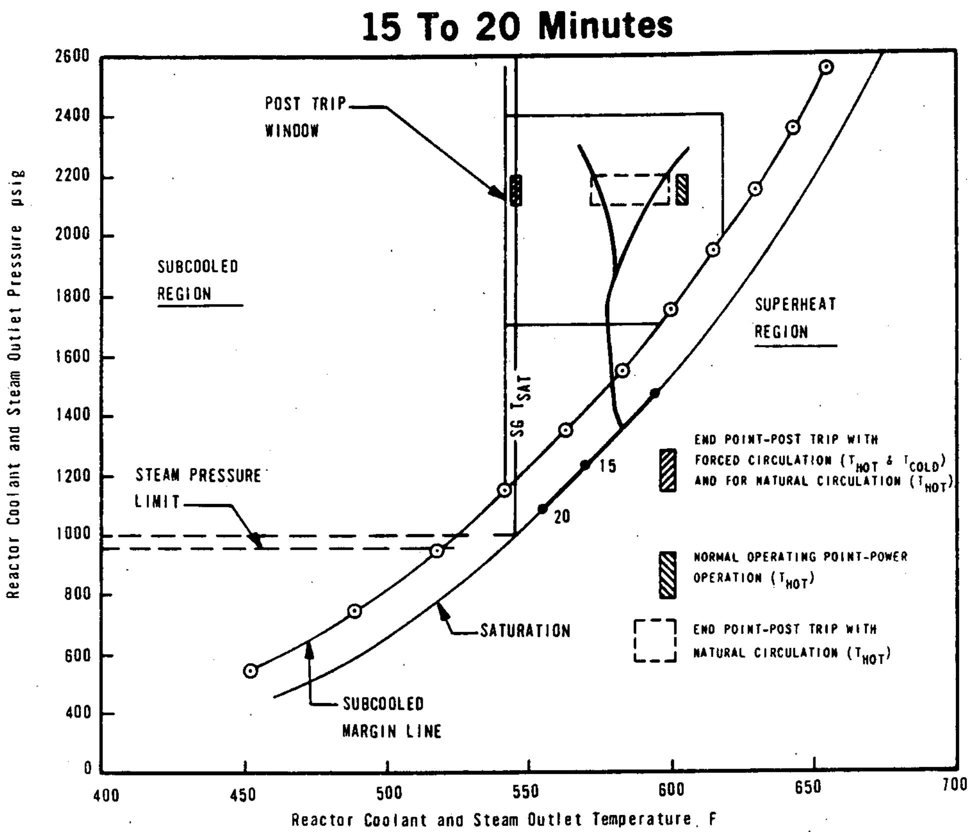


Figure 4D 15 to 20 minutes:

Primary-to-secondary heat transfer (coupling) is now almost completely restored. Thot and Tcold are approaching their normal post-trip values. However, the inadequate subcooling margin is still evident.

As shown by these examples, the symptoms of interest can be combined simply as shown on a cathrode ray tube. With a relatively few number of input variables, the operator can monitor the real-time progression of the transient. If one

such display is used for each reactor coolant system loop (because of possible asymmetric loop conditions) the operator has a continuous, complete record of the entire event. This record allows initial diagnosis, positive feedback on corrective actions, and early detection of subsequent malfunctions that may occur.

2.4.4 ATOG Organization

Once the symptoms are identified and a method of monitoring those symptoms developed, the next step is to reduce this information into something useful to the operator. The Abnormal Transient Operating Guidelines comprises two parts. The first part is procedural guidance to be used in the control room during transients. The second part, consisting of two volumes, is a training aid explaining the design bases for, and the use of, the procedures.

Table 1 outlines the organization of Part I. The immediate actions are common to every reactor trip and must be performed regardless of the cause. The vital system status verification is a checklist used to determine a baseline for possible operator actions. This checklist considers instrumentation power supplies, engineered safety features actuation system status, steam line break protection system status, etc. Included in this checklist is a requirement to monitor the ATOG display. If everything is normal, the plant has responded as designed and come to a steady

post-trip condition. No further action is required. However, if a symptom has developed, the operator will diagnose it and be directed to the appropriate section for follow-up actions. A fourth section is provided for the special case of steam generator tube rupture. A tube leak may not initially affect one of the three basic heat transfer symptoms and is therefore diagnosed mainly by radiation monitoring. This allows actions to be taken to minimize radioactive release expeditiously. These sections treat the symptoms and do not require the operator to determine the cause. It is expected, however, that as he treats the symptoms he will find the original problem.

Treating the symptoms will allow returning the plant to a stable condition. This stable condition could very well be abnormal compared to what the operator normally sees. Accordingly, various cooldown procedures are provided to give him guidance on long-term recovery from these possible conditions. In addition, guidance is given in the extremely unlikely event that reactor coolant system P-T conditions enter the superheat region, indicative of inadequate core cooling (ICC).

The actions described above will maintain adequate core cooling. The emphasis in this method is to place the plant in a safe, stable configuration, then followup to determine the cause and affect repairs.

TABLE 1 ATOG - ORGANIZATION OF PART I

Section I	Immediate Actions
Section II	Vital System Status Verification
Section III	Follow-up Actions for:
	A. Lack of adequate subcooling margin
	B. Lack of primary-to-secondary heat transfer
	C. Too much primary-to-secondary heat transfer
	D. SG tube rupture

Cooldown Procedures:

- Large LOCA
- Normal
- Saturated RCS
- HPI cooling
- Solid water cooldown
- Inadequate Core Cooling

Table 2 outlines the organization of Part II. Intended to give the operator a thorough understanding of Part I, it conveys the writer's intent as to why various steps are taken in Part I. It also describes, using many graphic examples, the expected plant response based on information gathered during the guideline development stage. Part II has been written to aid the operator's training and is important to the guidelines because an intelligent, capable operator is a basic part of the plant operating structure in which the guidelines are built (i.e., the guidelines optimize the operator's effectiveness instead of minimizing his impact).

TABLE 2 ATOG - ORGANIZATION OF PART II

Volume 1 Fundamentals of Reactor Control for Abnormal Transients

A. Heat Transfer

B. Use of the P-T Diagram

C. Abnormal Transient Diagnosis and Mitigation

D. Backup Cooling Methods

E. Best Methods for Equipment Operation

F. Post Transient Stability Determination

G. Fundamentals of Reactor Building Control

H. Use of the Guidelines

Volume 2 Discussion of Selected Transients

A. Excessive Main Feedwater

B. Loss of Main Feedwater

C. Steam Generator Tube Rupture

D. Loss of Offsite Power

E. Small Steam Leak

F. Loss of Coolant Accident

2.4.5 Guideline Validation

Once written, the potential guidelines were tested on a PWR simulator by imposing multiple casualties and using the guidelines to recover. Guideline credibility was also established by back-checking the guidelines against event tree paths and benchmarking event tree paths and computer simulations against actual plant transients. The event trees were also reviewed by the utility operators to take advantage of their plant experience. The draft guidelines were sent to the plant site for walk-through drills to test their applicability. Feedback from the operator to the plant designer served to greatly reduce communication errors and increase confidence in the final guidelines.

An important final step in validation involves implementing the guidelines into the plant procedures system. This implementation tests the guidelines scope and appropriateness since they must be a workable part of the overall plant procedures system or their worth diminishes. Existing post-trip procedures must be checked against the guidelines to determine the following:

1. Necessary actions outside the development program scope but needed for a post-trip procedure in the same time frame (e.g., verifying source range high voltage on at a predetermined point in the intermediate range following a reactor trip). This assures that the adoption of ATOG does not decrease in any area the adequacy of procedures from the previous level.

Some actions in the previous procedures may be found good but not necessary, and can either be deleted or relegated to a lower level of instruction. The goal is to maximize simplicity.

2. Actions that should be included in an instruction for longer term action. Current post-trip procedures include many necessary follow-up actions that are not appropriate for ATOG, but must be included somewhere. Three steps (identification of these items, determination of the form in which they should be given, and optimization of the interface between this form and ATOG), are necessary to make ATOG a workable part of the overall plant procedure system. Again, the goal is to maximize simplicity.

3. Any post-trip procedures not accommodated by ATOG, but which must remain intact. One goal of ATOG is to eliminate these procedures, but any such procedures identified must be entered in a manner compatible with ATOG implementation.

Although procedures vary from plant to plant, most of the applicable steps from the existing plant procedures have already been included in Part I with the intent that ATOG would replace a certain minimum group of procedures including: reactor/turbine trip, LOCA, LOFW, steam line break, overfeed, SG tube rupture, and LOOP. Using Part I to replace at least these plant procedures is desired for several reasons:

1. To incorporate the emergency procedures into one function-oriented procedure as suggested by NUREG-0899 (reference 5.5) which will ensure its availability during an accident situation.
2. To provide a concise, readily applicable method for handling any transient regardless of the cause (this is the unique ability of ATOG).
3. Part I has been written for the operator with human factors input in assuring its correct interpretation by the operator.
4. Most importantly, Part I was written to coincide with methods used by skilled operators (experienced operators helped write Part I to ensure its usefulness during real situations).

2.4.6 Summary

By using the Abnormal Transient Operating Guidelines, the operator can ensure plant safety by monitoring reactor post-trip parameters for only a small number of symptoms and taking corrective action as directed by the procedure. The guidelines allow him to use one simple procedure for all transients which start with a reactor trip or forced shutdown. The unique feature of this approach is that it provides a commmon starting point, independent of the initiating event, and leads the operator through a step-by-step procedure to regain stable plant conditions without having to identify either the cause of the transient or any additional post-trip malfunctions.

3.0 PART I USAGE

3.1 Philosophy of Part I Organization

Part I is designed for use following any reactor trip or forced shutdown. Its primary purpose is to maintain core cooling and ensure plant stability (i.e., obtain a safe and stable plant configuration). A reactor trip, depending on the cause and initial plant conditions, can result in demands on various systems and components (MSSV's, TBV's, EFW, etc.). These demands, coupled with the cause of the trip or forced shutdown, are occurrences that have a higher probability for abnormal conditions to develop.

When equipment or system failures occur resulting in an abnormal plant response following a trip, it is not so important to immediately identify the cause as it is to restore stable, controlled conditions. Once the plant has been stabilized, then time exists for failure identification and the decision for future operations (i.e., return to power, remain at existing conditions, or begin controlled cooldown). The main thrust of ATOG, and certainly the most important aspect of dealing with any transient or accident, is to maintain adequate core cooling. The most expeditious and positive approach to accomplish this objective is to recognize abnormal conditions when they develop and take appropriate actions to restore stability.

Part I of ATOG contains four basic sections that flow in a logical sequence based on this philosophy. The four sections, in order, are:

a. Section I: Immediate Actions

b. Section II: Vital System Status Verification

c. Section III (A-D): Follow-up Actions for Key Symptoms

d. Cooldown Procedures (including Inadequate Core Cooling)

The immediate actions in Section I are those actions taken after every reactor trip regardless of cause (e.g., manually tripping the reactor and turbine). Once the immediate actions have been performed, the next priority is to verify that the reactor is shutdown and that key systems and equipment are available and functioning properly (e.g., NNI/ICS power, turbine stop valves shut, etc.). These items are included in Section II. One abnormal transient (excessive MFW), should it occur, can require prompt recognition and response by the operator to prevent the possibly severe consequences of water spillover into the steam lines. Therefore, one of the first checks in Section II is the verification that MFW flow has runback. The important items to check early are reactor/turbine trip and MFW flow status. No particular importance should be placed on the sequencing of the other verification steps as long as all of them are performed.

Section II also includes obtaining a status of the four main symptoms of abnormal transients (the three basic heat transfer symptoms and the special case for tube rupture). However, operator training should emphasize continuous surveillance for indications of off-normal conditions. The four main symptoms are:

1. Lack of adequate subcooled margin
2. Lack of primary to secondary heat transfer (overheating)
3. Excessive primary to secondary heat transfer (overcooling)
4. Indications of steam generator tube rupture

Recognition of these symptoms is covered in more detail in the "P-T Diagram" and "Abnormal Transient Diagnosis and Mitigation" chapters in Volume 1 of Part II of ATOG. Should any of these symptoms occur, Section II references the operator to the appropriate follow-up action in Section III of Part I.

3.2 Philosophy on the Use of Section III

The order that the symptoms are listed in Section II corresponds with the order of the respective follow-up actions in Section III and is based on the relative priorities of the corrective actions. Lack of adequate subcooling margin is of course top priority because core cooling cannot be assured until certain actions are performed. If a lack of adequate subcooling margin occurs, tripping the RC pumps and initiating full HPI flow must be performed quickly. While ICC is the most severe condition of the RCS, it follows after a lack of adequate subcooling margin and the operator would be directed to the ICC section if it should occur. However, if the actions in the lack of adequate subcooling margin can be performed, ICC will not occur. Lack of heat transfer and excessive heat transfer are both second priority symptoms. These two symptoms are equal in priority because they are mutually exclusive conditions. However, excessive heat transfer will require the quickest response by the operators. The SG Tube Rupture is the last priority symptom. The order of the priority for these symptoms can be understood by focusing on the objectives for treating any abnormal transient, which is to maintain adequate core cooling and minimize radiation release. For example, even though a SGTR occurs which can release large amounts of radiation if it is not quickly treated, the lack of adequate subcooling margin and the lack of heat transfer take precedence. This is true because, if adequate core cooling is not maintained, the radiation release would be much greater.

Again, even though it is important to diagnose and treat a steam generator tube rupture as soon as possible, termination of a concurrent overcooling transient takes precedence. This is true because:

1. The overcooling could be the result of a steam leak to atmosphere on the steam generator with the tube rupture, resulting in higher offsite releases.
2. The overcooling increases the tensile stresses on the steam generator tubes which could result in a larger leak size.
3. The contraction of the RCS liquid volume due to the overcooling, especially when compounded by the inventory loss through the tube leak, could result in draining the pressurizer and saturation of the RC loops. Subsequent voiding in the loops can significantly delay the cooldown and thus lead to increased offsite releases.

This discussion of priorities is given to show the logic behind the development of Part I. The important point to remember is that the operator should always be alert for the presence of these symptoms and should always proceed directly to the appropriate section for follow-up actions for a symptom without necessarily waiting to see if a "higher priority" symptom develops. This constant operator surveillance should continue during and after the stabilization of a transient. Some symptoms can mask the presence of others. For example, an overcooling transient can mask the presence of a small LOCA. However, once the overcooling transient is terminated, the small LOCA should quickly become evident. Abnormal transients can

occur at any time and will not always oblige by beginning immediately after a reactor trip. Therefore, continuous surveillance is warranted at all times, i.e., anytime a symptom occurs the operator takes appropriate action.

One symptom, lack of adequate subcooling margin, always requires immediate attention. The operator must trip reactor coolant pumps and initiate HPI flow immediately whenever the subcooled margin is lost regardless of which part of Section III he is currently following. For this reason, the other parts of Section III will either a) reference the operator to section III.A <u>or</u> b) reiterate the required actions given in Section III.A for loss of subcooling margin.

It can be seen that these symptoms can occur in various combinations and virtually at any time during a transient or subsequent cooldown. Thus it would be very difficult to write a comprehensive procedure that will lead the operator through any possible sequence of events. Where it is known that multiple symptoms are more likely to occur the guidelines will specifically address the possibility. However, to ensure maximum coverage this approach is supplemented by a combination of operator training and procedural guidelines. Recognition of the four basic symptoms and following the appropriate actions of Section III will provide plant stabilization for all single events regardless of cause. Operator training is the key in the recognition and understanding of the four basic symptoms. When events become more complex, either due to

additional failures or due to an event progressing to the point of inducing other symptoms (e.g, loss of subcooling margin), operator training is again the key in successful mitigation. The procedural guidelines contain all the necessary information, but the operator must know when to implement the appropriate sections. He does this by careful surveillance of the plant conditions during and following a transient, recognizing the symptoms whenever they occur and going to the appropriate section. In this respect ATOG is somewhat similar to event-oriented procedures in that the operator must recognize a condition and react to it. The difference is that the symptom will always be evident when the failure occurs. The cause (event) will not always be evident. Also, there are just four symptoms to recognize as opposed to numerous events.

In addition to recognizing a symptom and implementing the appropriate part of Section III, the operator must also know when to transfer between parts of Section III (for multiple symptoms or incorrect diagnosis) and when to terminate his actions if the problem is corrected. Some basic instructions for the use of Part I can be summarized as follows:

1. Priorities between the parts of Section III:
    a. Loss of subcooling margin always requires immediate attention regardless of which part of Section III is being followed (with the single exception of raising SG levels noted in 1.c below).
    b. Lack of heat transfer or excessive heat transfer must be corrected before, or at least concurrently, with actions for SGTR.

c. Excessive heat transfer (overcooling transients) must always be terminated as soon as possible, and before raising SG levels to high level for loss of subcooled margin.

2. Follow the appropriate part of Section III for the dominant symptom, unless a "higher priority" symptom (in item 1 above) appears, in which case recycle to the part of Section III for the higher priority symptom.

3. If a reactor trip occurs during a forced shutdown, recycle to Section I.

4. If a major change in equipment status occurs during the performance of a part of Section III or subsequent cooldown, carry out the appropriate actions of Section II (i.e., loss of NNI/ICS power loss of offsite power, safeguards actuation, etc.). This can be accomplished in parallel with Section III.

5. If it is discovered that an incorrrect diagnosis has been made and:

   a. no other symptom exists (e.g., inadvertent entry into Section III because an overshoot after trip misinterpreted as overcooling), then stabilize plant (e.g., restore heat transfer; don't exit III.C immediately after isolating both SG's) and recycle to Section II; <u>or</u>

   b. a different symptom exists, then recycle to the appropriate part of Section III.

6. If, during the performance of follow-up actions in Section III, the cause of the transient becomes evident and is corrected,

then hold at that point and allow the plant to stabilize while checking for other symptoms/problems (e.g., if in the process of isolating both SG's for excessive heat transfer and closing of the TBV's on one SG stops the transient, there is no need to continue isolation of steam and feedwater on both SG's). Similarly, if the intent of a group of actions is satisfied, then continuation of those actions may not be necessary (e.g., HPI flow an be throttled and SG levels do not need to be raised to the high level once subcooling margin is restored).

7. All normal limits and precautions are applicable during the performance of Part I unless specifically superseded by the ATOG procedure (e.g., the use of pump bumps regardless of NPSH requirements when saturated with SG level). Whenever a step appears in Part I that supersedes a normal limit or precaution, it has been carefully considered and deemed acceptable for plant conditions existing at <u>that</u> point in the procedure (e.g., violation of fuel pin compression limits during a large SGTR). One should not infer, however, that since it is acceptable at one point in the procedure then it is always acceptable to violate the limit or precaution.

As an example on the use of Part I, assume an overcooling transient occurs following a reactor trip that leads to drainage of the pressurizer and a loss of the subcooling margin. When the subcooling margin is lost (the symptom) the operator must quickly perform the actions of III.A which include tripping the reactor coolant pumps and initiating full HPI flow (1.a above). The operator is also

required to raise SG levels. These actions are required in the event of a small break LOCA. In this case the LOCA could be masked by the overcooling or induced by the overcooling transient. The overcooling will be caused by either excessive feedwater flow or loss of steam pressure in one or both steam generators. The operator must either regain control of feedwater or isolate the loss of steam pressure (may require isolation of one SG) before proceeding with raising SG levels (1.c above). The intent is to terminate the overcooling first as it could otherwise continue to mask the presence of a small break and, if the loss of subcooling margin was due to <u>just</u> an overcooling event (i.e., no LOCA), then filling the SG's would be exactly the <u>wrong</u> action (it would aggravate the overcooling). Similarly, if the subcooled margin is regained while the operator is filling the SG's, he need not continue to the high level required for small breaks (6 above). The intent of the actions (restore subcooled margin and ensure SG's available for heat removal) has been satisfied. The operator should throttle HPI flow and adjust SG levels to the appropriate setpoint for natural circulation or forced circulation if he has restarted RC pumps. These variations on the use of the guidelines are examples of situations that, if Part I attempted to cover them all, would result in a procedure of such bulk and complexity as to render it useless. However, by training the operator so that he understands the process (i.e., heat transfer and what is really occurring in the plant) and what the guidelines are intended to accomplish, then his educated use of the guidelines will ensure transient termination and plant stability for any event or combination of events.

Another example of proper operator judgement can be shown by again assuming an overcooling transient. The guidelines may tell the operator to completely isolate both SG's (steam and feedwater). This is because Part I is designed to restore plant stability assuming worst case accidents, which, in the case of overcooling, would be an unisolable steam line break. If the operator does not know the cause of the overcooling or even which SG is causing the overcooling then the proper response <u>is</u> to isolate both SG's to stop the transient. With the transient terminated he should then be able to monitor secondary conditions and isolate the problem to one SG so that controlled decay heat removal can be restored using the unaffected SG. However, if he should discover the cause of the transient while he is isolating the SG's (e.g., stuck open TBV's), and isolation of this cause does indeed stop the overcooling, then there is no reason for him to complete the isolation of both SG's. If he understands the purpose of the steps he is taking in following the guidelines, then he will understand when that intent is satisfied and may be able to exit the procedure at that point rather than arbitrarily following it through to completion. Of course, should he fail to realize that isolation of the TBV's terminated the transient, continuing through the guidelines, including isolation of both SG's for this example, will not cause any significant problem; it is merely unnecessary. Continuing through the procedure will lead to restoration of core cooling using the unaffected SG(s).

3.3 Objectives of Section III

In order to promote understanding of the procedural guidelines, this section will address each subsection of Part I, Section III in terms of what the plant conditions are, what are the possible causes, and why the operator is directed to take the specified actions (i.e., what the actions are intended to accomplish). The referenced section of Part I should be followed while reading this section.

Section III.A, Follow-up Actions for Treatment of Lack of Adequate Subcooled Margin

Whenever plant conditions reach or cross over the subcooled margin curve the assumption is that the RCS is saturated. The RCS can become saturated as a result of three basic causes:

i. loss of coolant inventory (LOCA)

ii. overcooling that results in sufficient coolant contraction to drain the pressurizer, or

iii. prolonged loss of heat transfer that allows the RCS to overheat to saturation at high pressure (this cause would be recognized as lack of heat transfer before loss of subcooling and handled in accordance with Section III.B).

The primary objectives of this section are to 1) restore subcooled margin and 2) maintain or restore core cooling. To accomplish these objectives, HPI must be initiated and either secondary heat transfer or HPI cooling must be established.

Two actions are _always_ required whenever the subcooling margin is lost:

1. trip all reactor coolant pumps and
2. initiate full, balanced HPI flow.

These actions are necessary in the event the loss of subcooled margin is due to a small break LOCA. Tripping the RC pumps must be done immediately following the loss of subcooled margin to minimize inventory loss if a small break exists. In addition, if the loss of subcooled margin was the result of an overcooling transient, HPI will compensate for the coolant contraction and restore subcooling. Re-establishing controlled secondary heat removal should then be possible. If the loss of subcooled margin was due to a total loss of feedwater (main and emergency) then full HPI will be needed to establish HPI cooling (in Section III.B). In this case subcooling should also be restored but it may take some additional time until the cooling capacity of the HPI flow exceeds the core heat generation rate.

Raising SG levels should also be done in the event of a small break LOCA. High SG levels will allow condensation of steam voids in the RCS side of the upper tube region to establish boiler-condenser cooling. If the transient was initiated by total loss of feedwater then the operator may not be able to restore feedwater and raise SG levels, but after he has established HPI cooling (in Section III.B) he should continue efforts to restore feedwater. If the transient indicates overcooling then he should not raise level in the affected SG(s) until the overcooling is corrected. This is to

prevent further uncontrolled plant cooldown. Actions are also included to isolate possible causes for the loss of primary pressure.

At this point the operator has full HPI flow, the RC pumps are off, he is raising or attempting to raise SG levels, and he has isolated possible causes of the loss of subcooling. Further actions will be determined by the plant response to the actions already taken. The subcooling margin may be restored by HPI or the plant may remain at saturation. In either case, primary to secondary heat transfer may or may not exist.

<u>Subcooled Margin Restored</u>

If the subcooled margin is restored, the operator should restart reactor coolant pumps. This will aid in establishing primary to secondary heat removal if it does not already exist and will provide better mixing of the cold HPI flow to alleviate the brittle fracture concern. He will also throttle HPI flow to prevent excessive RCS pressure that could lead to NDT violation and/or unnecessary lifting of the pressurizer safety valves.

If primary to secondary heat transfer does not exist even after the subcooled margin is restored, it is probably due to a lack of feedwater or a blockage of RC flow due to steam voids in the hot legs. The operator will proceed to Section III.B which will provide for restoration of feedwater and primary to secondary heat transfer or establishment of HPI cooling.

If excessive heat transfer exists, the operator will proceed to Section III.C. The operator should also be alert for indications of a small break (refer to Appendix F in Volume 2) as a small break could exist that is within the capacity of the HPI system.

If controlled primary to secondary heat transfer exists, then the operator should regulate feedwater flow to establish SG levels at the appropriate setpoint (dependent upon whether RC pumps were restarted). The operator should also control steam pressure to prevent RCS reheating and swell. If the RCS were allowed to reheat, the added inventory from HPI could result in a large pressure increase and possibly a full pressurizer.

Subcooled Margin not Restored

If full HPI flow does not restore the subcooled margin even with heat transfer to the SG's, it is a LOCA. If heat transfer does not exist or exists in only one SG, the operator will proceed to Section III.B to attempt restoration of heat transfer to both SG's. The prolonged period at saturation may be due to a total loss of feedwater or a small break. In either case, restoration of feedwater flow in III.B will aid primary cooling. If, however, the CFT's are empty, a large break exists and primary to secondary heat transfer cannot be regained. In this case the operator will go to CP-101 for long term cooling following a major LOCA.

NOTE: Whenever adequate subcooling margin does not exist, the operator should be alert for indications of superheat in

the RCS (Th RTD's and incore thermocouples read higher than saturation temperature for the existing RCS pressure). If indications of superheat occur, the operator should proceed to the Inadequate Core Cooling (ICC) guidelines.

Summary

The bases for Section III.A can be summarized as follows:

Symptom: RCS pressure-temperature to the right and/or below the subcooled margin curve.

Problems:
- a) Possible LOCA
- b) Void formation in RCS at saturation can interrupt core cooling

Objectives:
- a) Restore subcooled margin
- b) Maintain or restore core cooling:
  - i. preferably with SG's
  - ii. with HPI cooling (after transfer to Section III.B) if SG cooling unavailable

Key Points:
- a) Be alert for indications of ICC
- b) Lack of subcooled margin can severely hamper primary to secondary heat transfer
- c) HPI cooling, while adequate for interim core cooling, is not a stable long-term cooling mode. Cooling with one or both SG's must be restored as soon as possible. (HPI cooling is discussed in more detail in the "Backup Cooling Methods" chapter in Volume 1 of Part II).

Section III.B: Follow-up Actions for Treatment of Lack of Primary to Secondary Heat Transfer in Either OTSG

If adequate subcooled margin exists, the most likely cause for lack of primary to secondary heat transfer is no heat sink (loss of feedwater). The operator will take steps to restore feedwater. If he cannot restore feedwater he will establish HPI cooling and he should reduce the number of running RC pumps to one (this minimizes heat input to the RCS while eliminating the brittle fracture concern by providing some forced flow). This will provide adequate core cooling while he continues efforts to restore feedwater to at least one SG.

Lack of Adequate Subcooling Margin

If, however, adequate subcooled margin does not exist, then the lack of heat transfer could be due to no heat sink (loss of feedwater) and/or no reactor coolant flow (hot leg voiding). The primary objective is to restore core cooling. The preferred method of core cooling is with primary to secondary heat transfer.

As in Section III.A, the operator will trip the RCP's and initiate full HPI flow when the subcooling margin is lost. If the operator has feedwater flow and a level in at least one SG, then the lack of heat transfer is due to lack of RC flow. If the CFT's are empty, a major LOCA has occurred and there is no benefit in restoring primary to secondary heat transfer. In this case the operator will proceed to the procedure for long term cooling following a major LOCA. If a major LOCA has not occurred, he will attempt to induce natural circulation flow by raising SG level(s) and lowering SG

pressure. If this fails, and RCP's are operable, he will attempt to induce natural circulation flow by bumping an RC pump. With the SG available as a heat sink, bumping an RC pump will force steam voids in the RCS into the SG tubes where they can be collapsed. Fifteen minutes should be allotted between successive pump bumps to allow natural circulation flow to build. If natural circulation flow is still not established after all operable RCP's have been bumped <u>and</u> one hour has passed since the reactor trip, a pump should be started and run, if possible, in a loop with the SG available as a heat sink. The hour limitation is based on allowing decay heat to decrease to a level that the HPI flow can accomodate so that additional inventory loss through the break due to forced flow is no longer a concern.

If the RCP's are not operable, the operator must cool the core with HPI and he will go to CP-104 for HPI cooling. If he is successful in establishing primary to secondary heat transfer then he will go to the appropriate cooldown procedure depending on the degree of subcooling. If the subcooled margin is not restored then a small break probably exists.

<u>Summary</u>

The bases for Section III.B can be summarized as follows:

Symptoms: a) With subcooled margin, symptoms are those indicative of loss of feedwater:

i. RCS reheating and repressurizing after normal post-trip cooldown

ii. Low or non-existent SG levels and feedwater flowrates

b) With lack of adequate subcooled margin, symptoms could be as above for loss of feedwater and/or small break symptoms (see Appendix F in Volume 2).

Problems:

a) Lack of core cooling.

b) Extended loss of feedwater will lead to saturation and loop voiding; necessitates HPI cooling.

c) Possible LOCA.

Objectives:

a) Maintain or restore subcooling margin.

b) Restore core cooling, preferably using the SG's

Key Points:

a) Lack of heat transfer with adequate subcooling is more than likely due to total loss of feedwater or insufficient feedwater to induce natural circulation.

b) Every effort must be made to restore primary to secondary heat transfer (unless a major LOCA occurred). HPI cooling will be adequate for short-term core cooling but is not a stable long-term cooling mode (see HPI cooling section in "Backup Cooling Methods" chapter in Volume 1 of Part II).

Section III.C: Followup Actions for Treatment of Too Much Primary to Secondary Heat Transfer

Excessive heat transfer is always caused by a failure in the control of secondary side parameters, resulting in a loss of steam pressure or excessive feedwater flow or a combination of both. The overcooling places large thermal stresses on the RCS piping and components and on the steam generators. It can also lead to saturation of the primary system if the RCS contraction is large enough to drain the pressurizer. The primary objective of this section is to terminate the overcooling transient and then to restore controlled decay heat removal.

HPI will be initiated by the operator if pressurizer level is low and RCS pressure is decreasing in an effort to prevent drainage of the pressurizer and subsequent loss of subcooling. The operator will then check to see if the SG causing the overcooling can be identified. The best method to identify the affected SG is to compare Tcold temperatures. The loop with a significantly lower Tcold is the loop with the affected SG. However, Tcold temperatures can be fairly close together even when only one SG is causing the overcooling. Since the primary objective is to first terminate the transient, both steam generators should be isolated if there is any doubt which SG is affected.

In either case (one or both SG's isolated), the affected SG will either:

a) stabilize in level and pressure if the overcooling was due to excessive feedwater or isolable steam leak, or

b) continue to lose pressure and level due to an unisolable steam leak.

If a), then controlled decay heat removal can be restored using both SG's (being careful not to unisolate a steam leak). If b), then the SG with the steam leak should be allowed to boil dry while decay heat removal is established with the intact SG.

Once controlled decay heat removal is established, the operator should check for indications of a tube rupture (since the tubes have been stressed by the overcooling) and verify adequate subcooling margin exists. If the affected SG was returned to service, then the check for tube rupture can be made using steam line monitors. If the affected SG was left isolated, then the operator should check for indications of a small break LOCA and continued cooling of the RCS by the isolated SG (due to boiloff of tube leakage). It should be noted that identification of a small break LOCA that is <u>not</u> a tube rupture (e.g., RCP seals) does not preclude the possibility that a tube rupture exists. The identified small break LOCA may mask the presence of a tube rupture. The important point is to assure that the unisolable steam leak is not a source of radioactivity release unknown to the operator. If adequate subcooling margin does not exist he should recycle to Section III.A.

Whenever an overcooling transient has been terminated, the operator should hold RCS temperatures at the existing values. If the RCS were allowed to reheat, the added inventory from HPI could result in a large pressure increase and possibly a full pressurizer.

Summary

The bases for Section III.C can be summarized as follows:

Symptoms:

a) Decreasing Tcolds and/or SG pressures and temperatures significantly below the normal post-trip cooldown.

b) Possibly high SG level(s) and feedwater flowrate(s).

c) Low RCS pressure and pressurizer level.

Problems:

a) Thermal stresses on RCS components and SG's (tubes).

b) Possible RCS saturation due to pressurizer drainage.

c) Excessive feedwater flow could result in water carryover into the main steam lines.

Objectives:

a) Prevent loss of subcooling margin due to RCS contraction and drainage of the pressurizer.

b) Terminate the overcooling.

c) Re-establish controlled primary to secondary heat transfer.

Key Points:

a) Comparison of loop Tcold temperatures is best method for identifying affected SG before SG isolation.

b) Comparison of SG levels and pressures is best method for identifying affected SG after both SG's are isolated.

c) Severe overcooling can induce tube leaks.

d) The RCS should not be allowed to reheat after the transient is terminated.

e) Unisolable steam leaks require boiling the affected SG dry to stop the overcooling.

Section III.D: Followup Actions for OTSG Tube Rupture

Several concerns exist whenever indications of a steam generator tube rupture become evident. In addition to being a LOCA, the primary inventory lost through the tube leak cannot be recovered for recirculation from the RB sump as it would for other LOCA's. Thus, it is important to cooldown and stop the tube leak before makeup capacity (BWST) is lost. However, it is also important to minimize offsite releases. Therefore, if at all possible, it is desirable to perform a controlled power runback and reactor shutdown at a power level less than the capacity of the TBV's rather than trip the reactor at high power. This prevents lifting of the safety valves on the SG with the tube leak which helps reduce overall releases to the atmosphere. Thus the primary objectives in mitigating a tube rupture are to minimize offsite releases and total tube leakage by performing an orderly but expedient shutdown and cooldown. Opening the TBV's before tripping the turbine and reactor (when power is less than total TBV capacity) will prevent lifting of the main steam safety valves.

Reactor Trip

If a reactor trip should occur or be required because the tube leakage exceeds HPI capacity, then it is important to ensure proper plant response, particularly with respect to steam and feedwater control. If a loss of subcooled margin occurs the RC pumps must be tripped and full HPI initiated. These actions are required for the same reasons as in any small break but, in addition, it is very important with a tube rupture to prevent void formation in the hot

legs which could block coolant flow and severely hamper the cooldown. It is also very important to terminate excessive heat transfer should it occur. Uncontrolled cooldown could also result in void formation in the hot legs and could overstress the SG tubes resulting in larger leak rates. Thus, if excessive heat transfer is indicated, the operator is directed to Section III.C to correct the condition before continuing in Section III.D.

During the period that the operator is performing the shutdown or stabilizing the plant after a trip, a survey of the steam lines should be made to verify which SG has the tube rupture. It is desirable to isolate the affected SG as soon as possible after primary temperature is low enough to preclude lifting of the main steam safety valves.

Cooldown Methods

Two basic cooldown methods are provided for tube ruptures, designated here as "normal" and "emergency." The method to be used is determined by the tube leak rate and the existing plant status. The differences between the methods are as follows:

	Normal	Emergency
1) Cooldown rate	$\leq$ 100F/hr	$\leq$ 240F/hr to 500F $\leq$ 100F/hr below 500F
2) Tube/shell ΔT limit	100F	150F
3) Fuel pin compression limit	Applies	May be violated if necessary

The factors determining use of the "normal" cooldown method are:

1) Tube leak rate within capacity of makeup system (minimal rate of BWST depletion)
2) Condenser available
3) RC pumps available

All 3 conditions must exist to use the normal cooldown. If any one condition is not met, the emergency cooldown method must be used. If, during the performance of the emergency cooldown, all three conditions are satisfied then the normal cooldown can be used. Conversely, if during the performance of the normal cooldown any one of the conditions is no longer satisfied, then the cooldown must be switched to the emergency method. In either case, the SG with the tube rupture should be isolated as soon as it is identified and Thot is 540F (to prevent lifting the steam safeties on the SG with the tube leak).

Loss of Offsite Power/RC Pumps Not Running

A loss of offsite power can significantly impact the mitigation of a tube rupture and therefore power should be restored as quickly as possible. While power is unavailable a natural circulation cooldown will be required. It will be necessary to periodically steam the SG with the tube leak during a natural circulation cooldown to induce loop circulation and avoid hot leg flashing in that loop. Void formation in the hot leg would hamper the cooldown due to the inability to depressurize the RCS (the hot leg would act as a pressurizer). If the condenser were not available steaming of the

affected SG would have to be done directly to atmosphere thus increasing offsite releases.

In addition, while RC pumps are not available, RCS pressure reduction must be accomplished using the pressurizer relief. This is a less desirable method since it repeatedly challenges the relief valve, results in additional inventory loss, and may degrade the reactor building environment. The cyclic operation between 50F subcooling and the minimum subcooling margin is a compromise between the need to limit the cycles on the relief valve and the need to maintain as low a pressure as possible to minimize the tube leakage rate.

<u>RC Pumps Running</u>

With RC pumps available, steaming of the affected SG can be reduced to the minimum necessary to keep the steam pressure less than 1000 psig and the level less than 95% on the operate range. This is required to prevent lifting of the steam safeties (additional release to atmosphere) and to prevent water spillover into the steam lines. Forced circulation will prevent the formation of steam voids in the idle (non-steaming) loop.

RCS pressure control is better with RC pumps and spray available. Therefore, spray should be used as necessary to maintain the RCS pressure as close as possible to the minimum subcooling margin to minimize the leak rate.

Continued Cooldown and Isolation of the Affected SG

The plant is not stable after a tube rupture until the tube leakage has been stopped. This will require cooldown and depressurization and DHRS operation to the point where the RCS can be drained to below the elevation of the tube leak. Therefore the cooldown should progress as expediently as possible.

Once the affected SG has been isolated, it should only be fed and/or steamed as necessary to maintain steam pressure $<$ 1000 psig and level $<$ 95% on the operate range and to maintain the tube/shell ΔT within limits. Excessive tube/shell ΔT could result in a higher leak rate due to the increased tensile stress on the failed tube. In addition, as previously stated, steaming of the isolated SG may be required during a natural circulation cooldown to prevent void formation in the hot leg.

Summary

Symptoms:

a) High radiation in steam lines and/or condenser

b) LOCA symptoms (decreasing pressure, unaccountable RCS inventory loss, etc.)

Problems:

a) SG tube rupture/LOCA

b) Unrecoverable RCS inventory loss (i.e., not available for sump recirculation)

c) Offsite releases

Objectives:

a) Minimize offsite releases

b) Terminate leakage before BWST depletion

c) Maintain core cooling/expedient cooldown and depressurization

Key Points:

a) Transient (leakage) not terminated until RCS cooled, depressurized, and drained below tube leak elevation

b) LOOP/natural circulation cooldown will probably result in higher offsite releases due to greater need to steam affected SG

c) Natural circulation cooldown necessitates use of pressurizer relief to reduce RCS pressure.

3.4 Cooldown Procedures/Inadequate Core Cooling

The objective of these guidelines is to maintain adequate core cooling by terminating transients and stabilizing the plant with controlled decay heat removal. Once stable conditions are achieved, further plant cooldown can be accomplished by existing plant procedures. However, the end conditions at stabilization following the execution of the guidelines will not necessarily coincide with the entry conditions for plant cooldown procedures. Therefore, procedures are provided in Part I to accomplish the transition from the guidelines to the plant procedures. Five cooldown procedures are provided to cover the five possible end conditions of the guidelines:

1) Cooldown following a large LOCA
2) Normal cooldown
3) Saturated cooldown with primary to secondary heat transfer
4) HPI cooling
5) Solid plant cooldown/recovery from solid plant.

A sixth procedure is provided for the special case of Inadequate Core Cooling (ICC). The philosophy and the objectives of the actions for ICC are discussed in detail in the "Backup Cooling Methods" chapter in Volume 1 of Part II.

Specific rules are provided at the end of the section containing the five cooldown procedures (immediately before the ICC section). These rules are provided in a separate section to avoid repetition throughout Section III of the guidelines. These rules apply

wherever they are referenced in Section III. Four specific rules are provided to cover:

1) Initiation of HPI
2) HPI flow control
3) Feedwater throttling methods
4) SG level setpoints

In addition, three figures are provided at the back of Part I for easy reference during the use of the guidelines. These figures provide:

1) HPI flow vs. RCS pressure
2) RCS pressure-temperature limits for brittle fracture/NDT
3) Core exit thermocouple temperatures for ICC

3.5 Operator Aids

In addition to the guidelines in Part I and the training material in Part II, two other developments of the ATOG program can provide significant assistance to the operator during the mitigation of abnormal transients: the pressure-temperature (P-T) display and the System Auxiliary Diagrams (SADs). The ATOG user should provide for full utilization of these aids in the implementation of the guidelines.

P-T Display

The information required to identify and track the symptoms discussed previously is already available in the control room. However, it consists of discrete displays for reactor coolant system hot and cold leg temperatures, reactor coolant system pressure and steam generator pressure. This format requires mental integration on the part of the operator to quickly assess plant cooling status using the individual displays and the steam tables. Thus, the problem is how these variables could best be displayed in real time to give the operator a simple and logical method of monitoring the symptoms of interest. The solution developed in ATOG was the use of a P-T display on a cathode ray tube (CRT). The display continuously shows the primary subcooling margin and the dynamic relationship of the primary to secondary heat transfer. The particulars of the display format and identification of the symptoms is discussed in more detail in Section 2.4.3. This section will discuss the various functions the display can perform to aid the operator.

Symptom Identification

The primary purpose for developing the P-T display is to provide the means for the operator to monitor the plant response following a reactor trip or during a forced shutdown to verify normal response and to quickly identify abnormal response should it occur. Section 2.4.3 describes the normal post-trip cooldown of the RCS and the various trends that can develop when the response is abnormal. With the P-T display, the operator can quickly recognize the loss of subcooled margin, lack of heat transfer or excessive heat transfer and proceed directly to the appropriate section of Part I to restore plant stability and core cooling.

Response Verification

The P-T display also provides positive feedback to the operator on the response of the plant to his actions. For example, after the loss of subcooling margin, the operator can easily determine the effectiveness of full HPI flow by monitoring the P-T display and determine when to throttle HPI flow if the subcooling margin is restored.

Controlling Within Limits

Certain operations require that the operator control the primary system within specified P-T regions that can readily be displayed on the P-T diagram. For example, the guidelines for a natural circulation cooldown with a tube rupture require maintaining RCS pressure within a region bounded by the subcooled margin line and

a P-T line approximately 30F colder. If the operator has the capability to select a second curve 30F colder for display on the CRT (the subcooled margin line is already displayed) then he has a simple, convenient format for monitoring the cooldown and ensuring compliance with the limits. Many other examples exist, including uses during normal plant cooldowns and heatups (e.g., fuel pin compression limits, NDT limits, etc.).

Power Operation

The CRT format is readily adaptable for displaying plant status information during normal power operation. Some examples for such usage are the reactor protection system pressure-temperature trip envelope (shown in the "P-T Diagram" chapter in Volume 1 of Part II) and power imbalance envelope. However, if the ATOG CRT is used for these displays, they should be of a secondary nature with the CRT automatically reverting to the ATOG P-T display on reactor trip.

Backup for the CRT

It can readily be seen that the availability of a P-T display improves the flow of information to the operator and enhances the use of Part I. Effort should be made in the implementation of CRT displays to provide high reliability.

However, control room personnel should allow for the possibility that the CRT displays are unavailable when needed. Provisions should be made to facilitate hand plotting of the parameters on a

P-T diagram similar to the diagrams depicted herein. Hand plotting is quick enough to provide data which can be used for plant control. The format of the diagram for hand plotting (with the saturation and subcooled margin lines pre-drawn) would allow for trend diagnosis and still be a significant improvement over mental assimilation of discrete data displays.

System Auxiliary Diagrams

System Auxiliary Diagrams (SADs) were developed in the ATOG program to identify supporting systems essential to the operation of systems having direct input to plant response. They also identify instrumentation required to verify proper operation of supporting systems.

The SADs serve as a useful aid in the event that a critical system fails. For example, the operator may be required to initiate HPI. In the highly unlikely event that a total loss of HPI occurs, the associated SAD can be used as a rapid troubleshooting aid to restore HPI operation. The SAD for HPI shows HPI in the center and various arrows pointing toward HPI which identify everything required to make HPI initiation successful. Pump power supplies, required cooling/lube oil sources, major inline valve positions, ventilation cooling, etc., are all identified along with available instrumentation to verify proper operation of the HPI system. Only those items that are within the operator's ability to control and can be accomplished quickly are included. Corrections that are longer term (e.g., replacing a pump impeller) are omitted.

Since troubleshooting will be performed by roving operators or maintenance groups, the SADs are packaged separately as opposed to being contained in the ATOG volumes. However, the appropriate SADs are referenced in Part I where applicable. Station management will determine the availability and use of the SADs.

SADs have been developed for the following systems and components:

1. Main feedwater system (loss of flow).
2. Emergency Feedwater System (loss of flow).
3. Steam line components (loss of steam pressure).
    a. Turbine bypass valves
    b. Main steam safety valves
    c. Atmospheric dump valves
    d. Turbine controls
4. ECC Systems (failure to deliver water).
    a. Makeup
    b. HPI
    c. LPI
5. Containment cooling systems (failure to depressurize containment).
    a. Building spray
    b. Building coolers
6. Containment isolation (failure to isolate).
7. Boron addition (inability to add boron).
8. Components for RC pressure control.
    a. Pressurizer heaters
    b. Pressurizer spray

3.6 Correlation Between Part I and Part II

At this point one can see that use of symptomatic procedures involves a different approach to plant control and requires a shift in emphasis in operator training. The operator is no longer limited by, nor is he required to solely rely on, the designer's foresight in providing the key alarms and indications for every conceivable event that could occur. The symptomatic approach of Part I will work, regardless of the event. By training on the ATOG approach, the operator will have a thorough understanding of heat transfer, plant control, and the various operations available for controlled core cooling when systems and equipment fail. Part II of ATOG was written to provide the basis for this understanding with the intent that it be used as part of the operator training program.

Part II, volume 1

Volume 1, "Fundamentals of Reactor Control for Abnormal Transients," provides the basic background necessary for understanding heat transfer and builds on this information to enable the operator to recognize abnormal conditions when they develop and take the appropriate actions to correct them. Volume 1 covers primarily information regarding the heat transfer process and mechanisms, including subcooling and natural circulation. Volume 1 also shows how to use the P-T diagram and this knowledge of heat transfer to diagnose abnormal transients and mitigate them.

The preferred method of core cooling is with controlled primary to secondary heat transfer and many abnormal transients involve restoring a balance to this heat removal path. However, this is not always possible. Therefore, Volume 1 discusses core cooling methods when the steam generators are not available.

Volume 1 also covers operational methods for key systems (feedwater, HPI, etc.) and equipment for various conditions and provides guidance on verification of plant stability.

Volume 1 contains a considerable amount of information and should be studied periodically for optimum comprehension and retention. Three major points should be kept in mind when reading Volume 1:

1. Understanding heat transfer is essential.
2. Relationship of symptoms and control functions.
3. Differentiating between rules and guidelines.

Heat Transfer

One aspect of plant control and the use of ATOG cannot be overstressed: the importance of understanding heat transfer and primary pressure-temperature relationships. A thorough grasp of the heat transfer process and P-T relationships will enable the operator to:

- recognize abnormal conditions (symptoms)
- evaluate plant response to corrective actions
- implement backup cooling methods when needed

Although virtually any event or combination of events could conceivably occur, they all present the common threat of disrupting core cooling. Thus, the major thrust of ATOG is to maintain some form of controlled core cooling, whether it be by the steam generators or ECC systems. Simply put, understanding heat transfer allows recognition of symptoms of abnormal transients. Recognition of symptoms allows implementation of the appropriate sections of Part I. Implementation of the appropriate sections of Part I and verification of plant response allows transient stabilization and restoration of controlled core cooling.

Symptoms and Control Functions

Recall from the discussion on Part I that Section III of the guidelines is divided into four main sections to address the basic heat transfer symptoms (lack of subcooled margin, overheating, and overcooling) and the special case of SG tube rupture. Part II discusses the importance of "Control Functions". The control functions are:

1. RC inventory
2. RC pressure
3. SG inventory
4. SG pressure

A fifth control function, reactivity, is also important in heat transfer considerations. However, reactivity is quickly controlled by automatic reactor trip, manual reactor trip, and/or emergency boration.

If control of one of these four functions is lost, it will impact primary to secondary heat transfer and become evident as one of the three symptoms. For example, a loss of SG inventory control low (loss of feedwater) will result in a loss of primary to secondary heat transfer (overheating). Conversely, a loss of SG inventory control high (too much feedwater) will result in excessive primary to secondary heat transfer (overcooling).

When a symptom appears, one or more of these functions are not being controlled properly. Regaining control of these four functions will restore controlled core cooling.

Rules and Guidelines

Volume 1 provides guidance on the operation of systems and equipment for many conditions and various events. When an action must always be taken for the conditions specified it is called a rule and is enclosed in a box for emphasis. For example, the RC pumps must always be tripped whenever the subcooled margin is lost, therefore it becomes the RC pump trip rule.

Whenever specified actions are recommended, but not always mandatory, they are considered guidelines. For example, Table 6 in Volume 1 provides guidelines for RC pump operation for different plant conditions.

ATOG was designed for maximum flexibility in order to address the spectrum of conceivable transients. Therefore, rules have been

kept to the minimum necessary. The user should remember, however, that the guidelines are also important and should be followed whenever they are applicable and feasible.

Part II, Volume 2

Volume 2, "Discussion of Selected Transients," provides detailed coverage of six specific initiating events. Although the ATOG concept is a break from the traditional event-oriented approach, Volume 2 was structured in this manner to meet the following objectives:

1. Validate the ATOG Concept

   Most operators involved in the initial implementation of the ATOG concept will be experienced with use of event-oriented procedures and may understandably be resistant to a different approach. Volume 1 discusses ATOG in a general overview manner and, standing alone, may not fully promote user confidence in the concept.

   Therefore, Volume 2 is provided to give examples of representative events and how the use of ATOG will lead to successful mitigation. Although the event is given, the diagnosis and mitigation is written with the assumption that the operator (in the example) is unaware of the specific cause.

In addition, the discussion on each transient demonstrates successful mitigation of events compounded by other failures using the same basic ATOG procedure. This highlights the relative simplicity of using a single, comprehensive procedure as opposed to several discrete procedures.

The transients depicted in Volume 2 are derived from more realistic analyses than previously used for design bases accident analyses. Thus, these transient discussions should give the operator a better feel for how the plant would actually respond should similar conditions occur. When available, actual plant data from representative transients is used.

2. Amplify Volume 1

The structure of Volume 2 provides a ready vehicle for conveying more detailed information about transient types (e.g., overcooling) and peculiarities and complexities of specific events. This is especially true for the appendices covering SG tube rupture and small break LOCA. These two events are unique in that they cannot be quickly terminated and stabilized. They impact many facets of plant operation and their mitigation is highly dependent on specific conditions at the time of occurrence (including the size of the leak). Consequently, considerably more event-specific information is provided in these two appendices.

4.0 ESTABLISHING THE ATOG BASES

Before symptom-oriented emergency plant guidelines could be developed, considerable work had to be performed to gain a thorough understanding of expected plant responses during many varied transients. These transients included classic singular initiating events as well as additional single and multiple component failures.

This section of the report describes each of the tasks that were performed in acquiring the necessary knowledge to form a baseline for the guidelines. The resulting ATOG bases and extent of coverage are also discussed. In addition, the last part of this section addresses each requirement of Section I.C.1 of NUREG-0737.

4.1 Individual Tasks

4.1.1 Safety Sequence Diagrams (SSD's)

A safety sequence diagram is a block diagram that identifies all the equipment necessary to achieve a stable plant condition following an upset. SSD's were developed for the following five events for each plant:

- Loss of feedwater
- Excessive feedwater
- Loss of offsite power
- Small steam leak
- Steam generator tube rupture

After completion of the main success path, failure paths were developed from the top of the tree downward. In general, the failure branches illustrate automatic system response based on plant design. The operator was added to the tree only when specifically required to do something by an existing procedure. Otherwise, the event tree proceeds as if the operator did nothing (the guidelines identify operator actions to regain plant control).

When a failure branch was developed, all of the major safety functions on the main path below the point of departure were also considered on the failure branch. This pattern was repeated on subsequent or multiple failures. To avoid needless confusion and repetition, not all subsequent safety functions were physically displayed on the event tree. Some failures are relatively insignificant with respect to the major failure being developed by the branch and therefore are not shown. For example, a failure path showing the loss of both main and emergency feedwater did not consider pressurizer heater failures.

A simplified event tree is shown in Figure 6. A complete event tree may contain dozens of paths, depending on the success or failure of particular systems or operator actions which are important to managing the specific initiating transient. However, it became evident when selecting failure branches for analysis that many individual paths ultimately led to similiar plant conditions that could be grouped under the basic symptoms of unbalanced heat transfer. This is reflected in the logic diagrams in Volume 2 of

Part II of ATOG which are essentially event trees that have been reduced to a pure functional level.

4.1.3 System Auxiliary Diagrams (SAD's)

A description of the SAD's and their intended use is provided in Section 3 of this report. In addition, the SAD's were used in the guideline development as an aid in the identification of effects of loss of service systems (instrument air, power, etc.). Figure 7 shows the SAD format and typical content.

4.1.4 Analysis

An essential element in producing a symptom-oriented guideline is the development of an in-depth understanding of expected plant responses during many varied abnormal transients. Much of this knowledge was acquired by studying existing plant casualty procedures and data from actual plant transients. Computer simulation and use of a PWR simulator provided the remainder of the data base from which the guidelines were developed.

The computer simulation portion of the analytical work was used to:

a. Obtain parameter trends and transient times to be used as examples in Part II of ATOG. In addition, this information sometimes led to establishing priorities for certain actions. For example, the analysis showed that a large excessive MFW flowrate could cause severe overcooling and lead to draining of the pressurizer in a few minutes after trip.

Therefore this one cause of excessive heat transfer is high-lighted in Section II of Part I under Vital System Status Verification.

b. Aid in the development of the Part I guideline. For example, one idea considered was to give the operator additional time to restore feedwater to the steam generators on a complete loss of FW by allowing him to delay the initiation of HPI cooling until the subcooling margin was lost. However, a realistic analysis of this transient showed that this could take 30-40 minutes, which was far in excess of previously generated 20 minute limits. The guidelines were revised to key operator action when primary-to-secondary heat transfer is lost. Another example was a proposal to identify the steam generator with a steam leak by differential pressure between the two generators. However, analysis showed that this differential pressure, because of the thermal mixing on the primary side, was transitory. Again, the guidelines reflect a more positive approach for identification.

c. Verify or correct event tree logic. For example, the original excessive main feedwater event tree showed transient termination by an automatic steam line break system actuation on plants so equipped. The analysis showed that this would not occur and the event tree was revised accordingly.

d. Enhance engineer and operator understanding of a steam generator tube rupture (SGTR) event. This is a continuing effort and the guidelines are being refined as our knowledge increases. Although not complete in this area, ATOG is far more comprehensive than any existing SGTR procedure in use today.

e. Compare with actual plant transient data for verification and to provide partial validation of the guidelines and the examples used in Part II of ATOG.

Analysis of follow-on plants (after Arkansas Nuclear One) was used to provide justification that their plant response closely resembled that of the lead plant such that the AP&L guideline analysis could be considered generic (i.e., benchmark that plant against AP&L). Where the event trees showed equipment differences that were significant to the point similarities were in doubt, that event tree branch received computer analysis.

The B&W simulator was used to:

a. Test various guideline ideas during the development phase.

b. Allow operators (under observation of the procedure writers) to test various guideline formats and provide input to the guideline development.

c. Test and develop the ATOG display.

d. Test and validate the final guidelines by inputting multiple failure event tree paths and using the guidelines to recover.

4.1.5 Human Factors Considerations

Virtually every facet of the ATOG development program considered principles of human factors engineering. Some of the more significant considerations are as follows:

a. The procedure format of Part I is structured along the recommendations of draft NUREG-0899. This format provides for easy identification of key decision points and the determinants to be used in the decision. In addition, the flowcharts provided for each section of the procedure have been simplified and provided as a fold-out at the end of the appropriate section to facilitate tracking through the procedure.

b. The ATOG display significantly enhances the man-machine interface by providing a concise, correlated display of the key parameters used in the identification of the basic heat transfer symptoms.

c. Walk-throughs of the procedure are conducted at each plant site to ensure that the procedure is compatible with the installed configuration of indicators and controls.

d. Kinton, Incorporated, was retained as a human factors consultant for the ATOG program. Their contribution consisted of the following:

    i. Conducted site visits to each program participant to interview operators for input to the guideline format and for determination of the required level of detail.

ii. Participated in training simulator exercises with AP&L operators using the draft ATOG guidelines to handle various multiple casualties. A significant observation was made during these exercises, that being that experienced operators have apparently been handling transients in a manner similar to the ATOG guidelines all along (i.e., using a symptom approach until steady state is achieved).

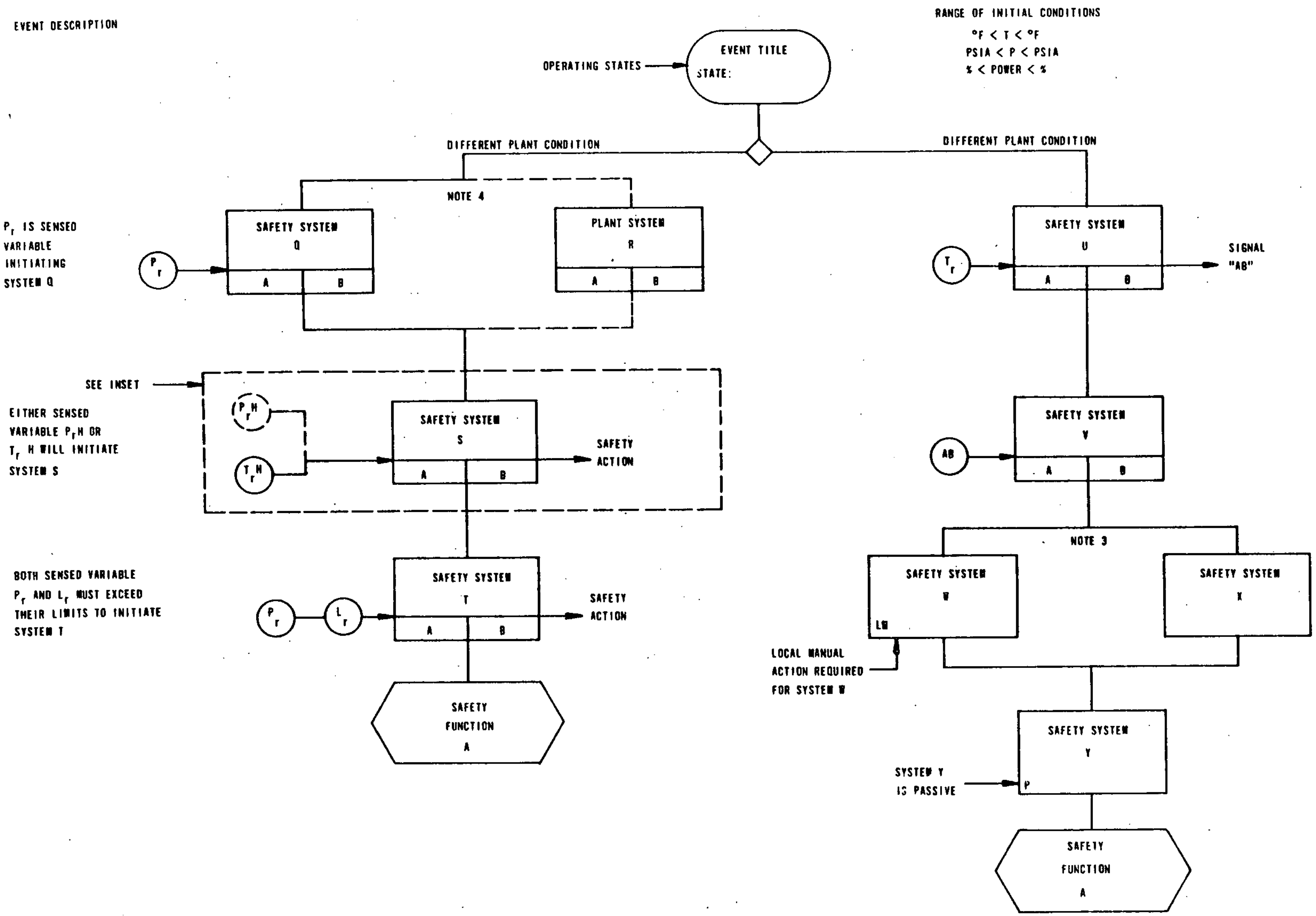
iii. Reviewed the SAD's and provided alternate formats.

iv. Developed logic diagrams for Part I as an alternate or redundant format for the action portion of the guidelines.

v. Completed a detailed review of Part I and Part II of the draft ATOG and issued a findings report (reference 5.6). This report provided several broad recommendations regarding format and content which were considered in the preparation of the final guidelines for implementation.

FIG. 5
SAMPLE SSD

EVENT CATEGORY



GENERAL NOTES

1. ALTHOUGH NOT SHOWN FOR ALL SYSTEMS ON THIS FORMAT DIAGRAM, UNLESS SAFETY SYSTEM IS PASSIVE A SENSED VARIABLE IS REQUIRED FOR EITHER MANUAL OR AUTOMATIC SYSTEM ACTION.

2. THE SAFETY ACTION FOR EACH SYSTEM IS TO BE SHOWN ASIDE THE SYSTEM.

3. SYSTEMS "W" AND "X" TOGETHER SATISFY INDEPENDENT FUNCTIONAL REDUNDANCE. PARALLEL SOLID PATHS INDICATE THIS CONDITION.

4. SYSTEM "R" ACTION IS NOT ESSENTIAL TO ACHIEVE SAFETY FUNCTION A. DUE TO PLANT CONDITIONS SYSTEM "R" IS EXPECTED TO OPERATE. DASHED PATHS INDICATE THIS CONDITION.

5. (SETPOINT) INDICATES THE VALUE OF THE SENSED VARIABLE AT WHICH THE SYSTEM IS INITIATED.

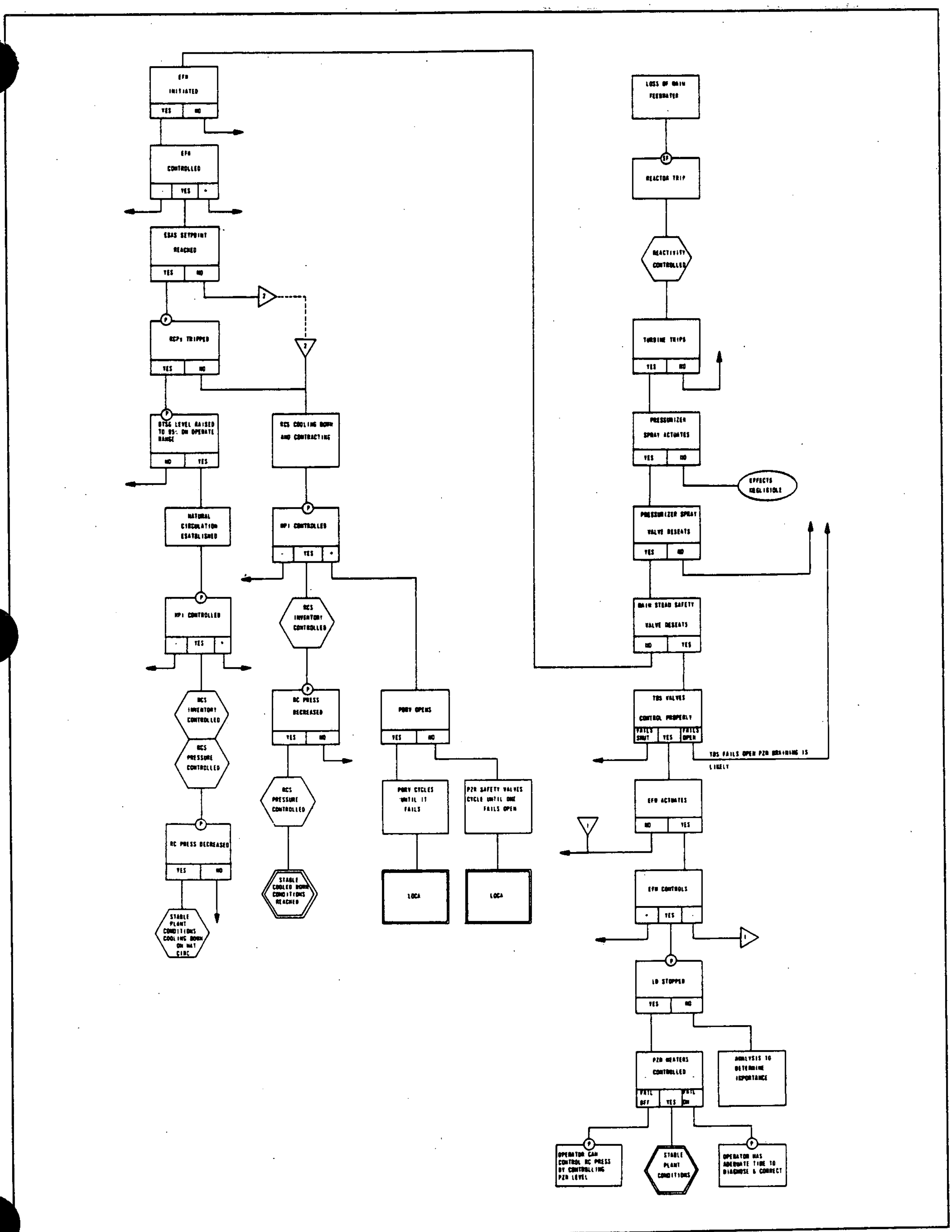
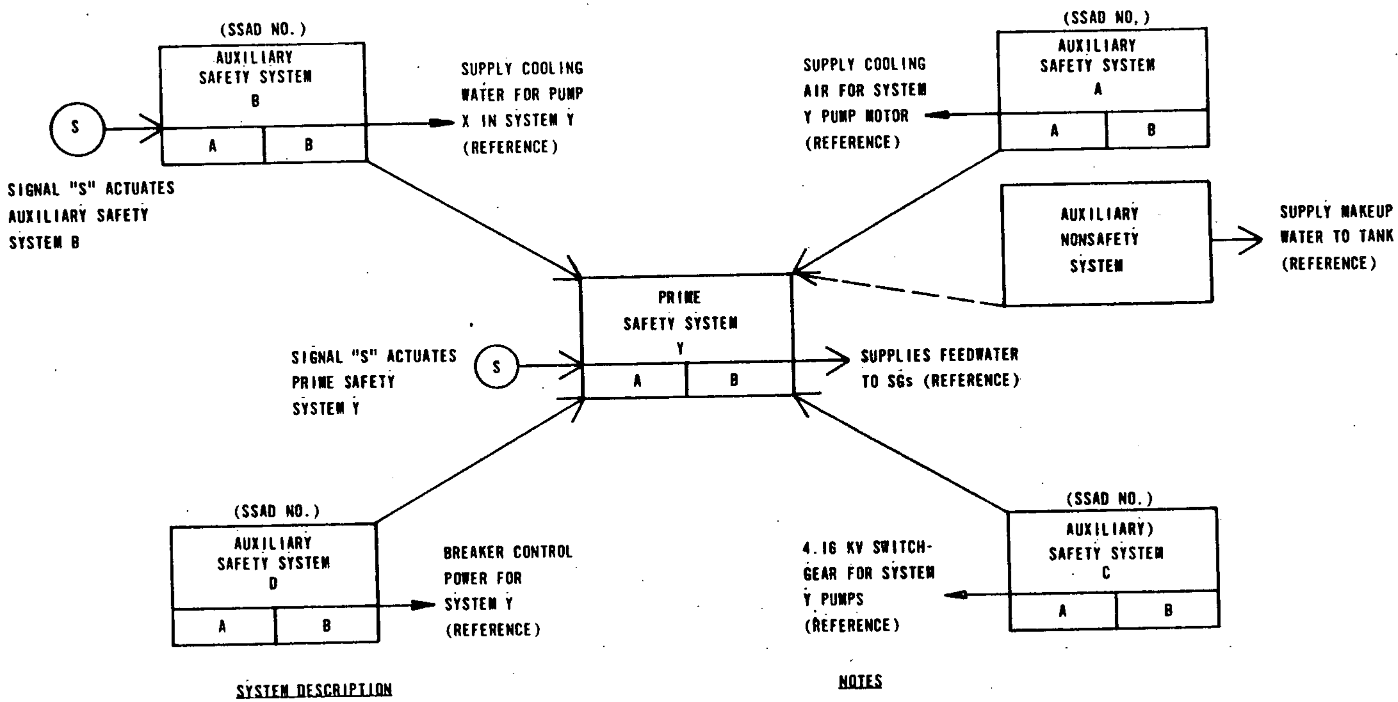


Figure 6 SIMPLIFIED LOSS OF FEEDWATER EVENT TREE

FIG 7
SAMPLE SAD



4.2. ATOG Bases

This section discusses the bases for ATOG in terms of scope definition, analytical methods and results, key assumptions, and the philosophy on equipment availability. Additional bases can be found in plant specific data on design and operation and in references 5.3 and 5.7-5.10.

4.2.1 Scope

ATOG emphasizes obtaining safe, stable plant conditions by addressing the five major safety functions: reactivity control, core heat removal, RCS heat removal, RCS integrity, and containment integrity. The ATOG guidelines have been written to cover a very large number of probable abnormal transient scenarios. This is an inherent benefit of a true symptom-oriented approach. However, for the purposes of defining the analytical scope and the events to be covered by Volume 2 of Part II, six initiating events were selected:

- Loss of main feedwater (LOFW)
- Excessive feedwater (Excessive FW)
- Steam generator tube rupture (SGTR)
- Loss of offsite power (LOOP)
- Small steam leak
- Small break loss of coolant accident (SBLOCA)

Since the number of specific events was necessarily limited, these six were chosen as representative of the basic symptoms on which ATOG is based (loss of subcooling, excessive heat transfer, inadequate heat transfer, and indications of tube rupture). Specific criteria used in this selection were as follows:

a. Moderate frequency events in which operator action is expected (excessive FW, LOOP, and LOFW).

b. Low probability events that can be confusing in recognition and mitigation (SGTR, SBLOCA).

c. The events cover a very large spectrum of everything that can occur in the RCS (overcooling, undercooling, loss of inventory).

d. Time exists for the operator to recognize and do something about the event therefore guidelines are appropriate (this <u>excludes</u> large, rapid FSAR events such as major LOCA's or major steam line breaks. Many FSAR events are design basis considerations as opposed to operator action studies).

4.2.2 Analyses

The base transient code used for the computer simulation portion of the ATOG program was TRAP 2. The version used for the Arkansas Nuclear One guidelines employed an equilibrium pressurizer model. Therefore, on transients involving insurges into the pressurizer, the insurge rates determined by TRAP were used as input into the DYSID code (a non-equilibrium pressurizer model, reference 5.9) to obtain the reactor coolant system pressure response. Subsequent transient analyses on follow-on plants used a newer version of TRAP (version 2.6, reference 5.8) which includes a non-equilibrium pressurizer model thus eliminating the need for DYSID runs on these analyses. The CONTEMPT code (reference 5.10) was used to predict building pressure response to steam leaks inside the reactor building.

The results of the analyses for each initiating event (including subsequent failures) are provided in a transient information document (TID). The TID's provide the link between the analyses and Part II of the guidelines. In addition, they tie the follow-on plant analysis back to the initial analyses performed on ANO. The information contained in each TID can be grouped as follows:

a. Major Plant Differences

The ATOG program is based on bringing the plant to a safe shutdown condition through the control of five major functions:

i. Reactivity

ii. Primary Inventory

iii. Primary Pressure

iv. Secondary Inventory

v. Secondary Pressure

This section of the TID discusses the systems that are used to control these functions for the particular event and how these systems compare with those on the lead plant. The comparison emphasizes differences that affect plant performance and includes a discussion of the system properties (flowrates, pressures, etc.) and function (i.e., actuation setpoints and actions performed by the system after actuation).

b. Plant Data

Data from actual plant transients is important as a basis for ATOG. It provides information on plant response and confirmation of TRAP 2 predictions.

Plant data for a single representative plant transient (if available) is presented. The TID includes plots of the data and a discussion of the event. Several of the ATOG Part II Appendices contain a similar presentation.

c. Predicted Plant Performance

This section discusses how the plant will respond to a given event compared to the lead plant. To make this comparison, the analyst utilized four sources of information:

i. TRAP 2 analysis for ANO

ii. TRAP 2 analysis for the follow-on plant

iii. Plant data as documented in the TID

iv. Plant comparisons as documented in the TID

The TID documents that the lead plant analytical work applies to the plant of interest directly, or identifies the expected plant response if it is different.

Each of the appendices in Part II of ATOG discusses a particular transient. This discussion includes a description of the general transient (i.e., the main success path on the associated event tree) and the transient combined with loss of each of the control functions. In order that the output from the TID's properly supports the Part II guideline, each TID provides:

i. A description of the required changes for each section of the respective AP&L appendix to

arrive at a valid appendix for the plant under consideration and reasons for the changes;

ii. Additional information which the analyst feels should be included in the appendix; and

iii. A plant specific plot for each figure in the appendix if different from the AP&L figure.

d. Additional Pertinent Information

This section includes additional information which the analyst feels is important to the transient being evaluated. For example, the analyst studying a loss of offsite power may want to discuss components loaded onto the diesel generators.

4.2.3 Assumptions

As stated in Section 4.1.2, certain assumptions were made early in the ATOG program to establish realistic boundaries on the scope. While ATOG is envisioned to expand in the future to address other plant modes and lower probability events, these boundaries enabled the development of an initial set of guidelines that cover most of the possible event scenarios within a reasonable time frame. The intent is to achieve a quantum improvement now in plant casualty control by implementing a set of guidelines to cover 95% of the spectrum while covering the remaining 5% with existing emergency procedures. ATOG can then be expanded to cover this 5% subsequent to the implementation of the initial set of guidelines. In this manner, the primary objective of preventing a recurrence of a TMI-2 type of event can be realized as soon as possible.

The assumptions that established the boundaries for the initial set of guidelines are as follows:

a. Initial Plant Conditions

The plant is considered to be in the range of reactor criticality up to 100% FP prior to the onset of the abnormal transient. Additionally, the thermodynamic principles apply anytime the RCS is full and pressurized. The guidelines may have to be expanded to cover such things as ESFAS being in low pressure bypass before they would apply to pre-event initial conditions all the way to cold shutdown. They now cover post-reactor trip all the way to cold shutdown.

b. Event Tree Development

The basic approach taken for developing event trees was to combine an initiating event with consequential failures. A consequential failure is defined here as a failure of any active system component that is challenged by the initiating event or by operator action. For example, on a reactor trip due to a loss of feedwater, the increasing steam pressure will initiate turbine bypass valve action. Because the turbine bypass valves are intended to open during this transient (challenged to do something), the event tree will consider the possibilities that they work properly or fail (open or closed). Equipment not challenged by the event (e.g., RB coolers for this example) will not appear on the tree.

c. Intial Equipment Status

All plant equipment (safety and non-safety) is assumed to be available at the time the transient occurs, although it may subsequently fail. However, this item is not significant in that it does not affect the structure of the guidelines or the operator's response. A detailed discussion on the ATOG philosophy regarding equipment availability is provided in Section 4.2.4 of this report.

d. Valid Instrumentation

Instrumentation readouts which provide the operator with information upon which he bases his actions will be assumed to read correctly. Instrumentation readouts which degrade and become biased because of adverse containment environments will be factored into the analysis and guidelines. The ATOG display contains a margin to the saturation line which allows for possible instrument errors under adverse conditions.

e. Operator Actions in Event Trees

i. The operator acts only when required by the procedures (e.g., trip RCP's on loss of subcooled margin).

ii. During the course of an event, the operator will be required to operate individual components. Assumptions for operator error at such times will be either completely correct or completely

incorrect, i.e., he will not manipulate one of two identical components correctly and the other incorrectly.

iii. The operator error to be assumed will not be random, i.e., he will focus on the component to be manipulated and not on some other component that is unrelated to the situation at hand. The event trees will show one of two error situations:

1) the operator fails to take action entirely (regardless of the time available), or

2) the operator performs an incorrect manipulation of a component that results in the worst condition.

iv. For evaluation purposes, the operator will not be assumed to correct errors, even though information may be available.

4.2.4 Philosophy on Equipment Availability/Failure Considerations

There are two basic ground rules behind the ATOG structure that establish the framework for consideration of equipment availability and failures. These ground rules are as follows:

a. ATOG Based on Installed Equipment

The objective of the ATOG program is to provide an improved method of transient control. ATOG is not a design adequacy study. Therefore the guidelines are written to cover operation of the installed plant equipment and configuration.

No equipment modifications or additions are required to implement the guidelines. Equipment changes resulting from other programs will be factored into ATOG when they occur.

b. ATOG Uses All Available Equipment

The guidelines employ a tiered approach to emergency operations. When abnormal conditions develop, the operator is directed to attempt regaining control of the function in question by first using the system or equipment best suited for that purpose. If that fails, he is directed to the next system or equipment that can restore control, etc. This approach continues until either control is regained or all available equipment has failed. In the latter case the operator would proceed to another mode to maintain core cooling with this loss of function. For example, for a loss of main feedwater (secondary inventory control function), if the operator cannot restore main feedwater he will establish (or verify) emergency feedwater flow. If this system also is unavailable he will attempt to feed the steam generators from any available source. If no source of feedwater is available then secondary inventory control cannot be regained. The operator will proceed to HPI cooling to maintain decay heat removal.

In following this tiered approach, it does not matter whether the system or equipment is classified safety or non-safety. This approach differs from the traditional

design bases criteria regarding safety/non-safety equipment in two significant respects:

i. Non-safety equipment is not assumed to fail during an accident merely due to its classification. If the equipment is available it is used.

ii. Failure considerations go beyond single failure criteria. It is not assumed that one of two redundant safety-grade components will always be available.

Another important aspect of the tiered approach is that failures are accounted for regardless of the mechanism causing the failure. The procedural guidance is the same if the equipment is destroyed by a fire as it is if the equipment lost power.

With the ATOG structure resulting from these basic ground rules, the following specific issues are addressed as noted:

a. <u>ATWS</u>

ATWS following an initiating event is considered to be an extremely unlikely event and the resolution of this generic issue is beyond the scope of the ATOG program. If this issue is resolved by means of equipment changes, ATOG will be revised to reflect those changes. In the interim, ATOG

addresses ATWS to this extent for the present plant configurations: the operator is instructed to manually trip the reactor and verify that control rods are on the bottom and that neutron counts are decreasing; if not, he is instructed to initiate emergency boration.

b. Multiple Failures

Multiple failures, including those that result in the total loss of a safety system, are inherently covered by the tiered approach to casualty control. As shown in the previous example, a total loss of feedwater is covered by HPI cooling. Conversely, if the HPI system completely fails, core cooling will be maintained by feedwater or restored by following the inadequate core cooling (ICC) procedure. Additionally, the system auxiliary diagrams (SAD's) will aid in restoration of system operation.

c. Natural Phenomena

Natural disasters such as fires, flooding, earthquake, etc., affect equipment operability and performance. If the equipment won't work or functions improperly, symptoms are affected. ATOG detects and treats symptoms through available equipment. Therefore, using a ground rule of working with the installed plant, fires and floods won't change the guidelines.

The real value of studying the effects of natural phenomena is not to determine operator actions but rather to determine, in advance, what can be done to the design, location,

or protection of the equipment to mitigate those effects. Such a study may produce equipment changes that would require guideline changes but that is a second order effect. The operator actions in ATOG are based on what equipment and control functions are lost, not why they are lost. Preparation for impending natural disasters and combatting fires are not appropriate subject material for abnormal transient operating guidelines and are addressed by existing plant procedures.

4.3 Compliance with the Requirements of NUREG-0737, Item I.C.1

NUREG-0737, "Clarification of TMI Action Plan Requirements," provides specifics on the implementation of items approved to date from the original Action Plan, NUREG-0660 (reference 5.11). Of these, item I.C.1 deals specifically with requirements for transient and accident procedures. This section addresses the compliance of the ATOG program and documentation with the requirements of I.C.1. Each requirement is stated and followed by a brief discussion of ATOG compliance. Where applicable, specific excerpts from the guidelines will be provided as examples.

a. I.C.1 Requirement

The initiating events to be considered should include the events presented in the final safety analysis report (FSAR), loss of instrumentation buses, and natural phenomena such as earthquakes, floods, and tornadoes.

ATOG Compliance

Any initiating event that results in a reactor trip or, as in the case of a tube leak, requires a forced shutdown is covered by ATOG. Many FSAR events (rod ejection, major LOCA, etc.) are so rapid that operator action is not possible prior to trip. These events are primarily design bases studies to show plant protection during the event without operator action. However, once the initial event is over, ATOG will provide guidance on post-trip plant control. Loss of instrument buses and the effects of

natural phenomena are covered by ATOG in the sense that these conditions may result in equipment failures that affect symptoms and/or the treatment of symptoms. The tiered approach of ATOG will provide plant control while actions are taken to restore equipment operability. Existing plant procedures are used for restoration of power supplies and plant preparation for impending natural disasters.

Excerpt from ATOG

"Part I is designed for use following any reactor trip or forced shutdown. Its primary purpose is to maintain core cooling and ensure plant stability. A reactor trip, depending on the cause and initial plant conditions, can result in demands on various systems and components (MSSV's, TBVs, EFW, etc.). These demands, coupled with the cause of the trip or forced shutdown, are occurrences that have a higher probability for abnormal conditions to develop.

When equipment or system failures occur resulting in an abnormal plant response following a trip, it is not so important to immediately identify the cause as it is to restore stable, controlled conditions. Once the plant has been stabilized, then time exists for failure identification and the decision for future operations (i.e., return

to power, remain at existing conditions, or begin controlled cooldown). The main thrust of ATOG, and certainly the most important aspect of dealing with any transient or accident, is to maintain adequate core cooling. The most expeditious and positive approach to accomplish this objective is to recognize abnormal conditions when they develop and take appropriate actions to restore stability."

b. <u>I.C.1 Requirement</u>

Consider multiple tube ruptures in a single steam generator and tube rupture in more than one steam generator.

<u>ATOG Compliance</u>

The existing ATOG guidelines address tube rupture in a single steam generator of varying leak sizes. Multiple tube ruptures in one or both steam generators are being addressed by a separate generic program. Appropriate changes/additions will be made to ATOG when the results of this program are obtained.

c. <u>I.C.1 Requirement</u>

Consider the failure of main and auxiliary feedwater.

<u>ATOG Compliance</u>

ATOG covers the total loss of feedwater to both steam generators by using a tiered approach to restoration of feedwater flow from any available source. If none exists, then core cooling is established using HPI flow.

Excerpt from ATOG

The following excerpt is from Part I, Section III.B., "Followup Actions for Treatment of Lack of Primary to Secondary Heat Transfer in Either SG":

"Lack of Feedwater Either Subcooled or Saturated

6.0 Initiate EFW

6.1 Feed both SGs, with EFW properly throttled, to the appropriate SG level (See Specific Rules 3.0 and 4.0).

6.2 IF EFW is not available, THEN use main FW.

6.3 IF neither EFW nor MFW is available, THEN attempt to feed one SG from an alternate source (emergency feedwater cross connect to another unit, service water, etc.).

6.4 IF the EFW system is not operating properly, THEN refer to the SAD section.

7.0 WHEN feedwater HAS been reestablished, THEN go to Step 10.0; until then, continue.

8.0 Establish HPI Cooling

8.1 Initiate HPI (See Specific Rule 1.0)

8.2 Open PORV block valve

8.3 Open PORV

8.4 Run one RCP per loop as long as adequate subcooling margin is maintained.

9.0 IF neither SG can be fed, THEN go to CP-104.

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There is no heat transfer to either SG. Natural circulation does not exist and cannot be induced due to a total loss of feedwater. The SGs are dry and the core must be cooled by HPI."

NOTE: PPS = Present Plant Status

d. I.C.1. Requirement

Consider failure of the high pressure reactor coolant makeup system.

ATOG Compliance

A complete failure of the high pressure injection (HPI) system is considered to be an extremely unlikely occurrence. However, ATOG addresses total loss of HPI as follows:

i. If the plant is otherwise stable with controlled primary-to-secondary heat transfer (i.e., following termination of an overcooling transient), the operator will maintain existing plant conditions to minimize demands on the HPI system.

ii. If continued depressurization and/or loss of inventory are unavoidable (e.g., small break LOCA), the operator will attempt to maintain core cooling by boiler-condenser operation of the SG's. If this is unsuccessful and HPI is still not available, inadequate core cooling (ICC) will develop and he will follow the ICC procedure.

In either case, plant personnel will continue efforts to restore HPI operation. System Auxiliary Diagrams are provided to aid this effort.

Excerpt from ATOG

The following excerpt is taken from Appendix A of Volume 2 of Part II, "Excessive Main Feedwater":

"Too little makeup or HPI flow, while undesirable, is not a major concern for this particular transient. If the overcooling is terminated before the pressurizer empties, the RCS will reheat and the resultant swell will restore pressurizer level. If the overcooling continues, ES will actuate and HPI will initiate. It is extremely unlikely that at least one HPI pump will not start; however, should that occur the RCS will lose subcooling margin. The operator will trip the RC pumps.

Control of FW to attain and maintain 95% level on the operate range will provide adequate core cooling while the problem with HPI is being corrected. The operator should throttle the FW flowrate to obtain gradual SG level increases and limit further overcooling."

e) I.C.1 Requirement

Consider an anticipated transient without scram (ATWS) event following a loss of offsite power, stuck-open relief valve or safety/relief valve, or loss of main feedwater.

ATOG Compliance

ATOG addresses ATWS to the extent of the capabilities of the installed plant configuration. ATWS is a separate, generic issue and its resolution is beyond the scope of ATOG. However, ATOG will be revised to reflect any plant changes that result from ATWS resolution.

Excerpt from ATOG

The following exerpt is from Sections I.0 and II.0 of Part I.

"Reactor Trip

a. Manually trip the reactor.

b. Manually trip the turbine.

c. Go to Section II."

"Section II

Vital System Status Verification

Verification Column	Remedial Action Column
VERIFY THE FOLLOWING	IF VERIFICATION CANNOT BE MADE, PERFORM THE FOLLOWING:
1.0 REACTOR POWER DECREASING ON INTERMEDIATE RANGE.	Start HPI from BWST.
2.0 ALL RODS ON BOTTOM	Begin emergency boration as necessary."

f) I.C.1 Requirement

- Consider operator errors of omission or commission.

ATOG Compliance

ATOG's consideration of operator errors is discussed in detail in Section 4.2.3 of this report. Briefly, in the development of the event trees, whenever operator action should occur two basic considerations were made:

i. that he failed to take any action (omission)

ii. that he took a wrong, worst case action (commission).

g) I.C.1 Requirement

Address the availability of systems and components under expected plant conditions and corrective or alternative actions that should be performed to mitigate the event should these systems or components fail.

ATOG Compliance

The ATOG philosophy in addressing equipment availability is provided in detail in Section 4.2.4 of this report. ATOG directs the operator to mitigate a transient first with the equipment or system best suited for that purpose. If that equipment is not available (for whatever reason), ATOG then directs the operator to the next level system, and so on. The sequential use of all backup systems and equipment provides the alternate actions. In addition, SAD's are provided to aid restoration of key systems and equipment to operation (corrective actions).

Guidance is also given in Volume 1 of Part II and the procedures of Part I on containment environment control to minimize equipment failures due to adverse conditions. Errors in key instrumentation that could occur due to a degraded environment in the reactor building are accounted for in the subcooled margin line on the P-T diagram.

h) I.C.1 Requirement

Analyses should be carried out far enough into the event to assure that all relevant thermal/hydraulic/neutronic phenomena are identified. Failures and operator errors during the long-term cooldown period should also be addressed.

ATOG Compliance

Each event tree path was developed to a final plant state that was either controlled and stable or covered elsewhere (e.g., controlled DH removal or LOCA). Any unique thermal/hydraulic conditions that were not previously addressed were then analyzed. The computer analyses were taken to the point where 1) the plant was stable, or 2) ramp rates and subsequent conditions were predictable. In the case of LOCAs, each path that ended in a LOCA was verified as being bounded by existing LOCA analyses. As stated in Section 4.2.3 of this report (item a.), ATOG covers post-reactor trip to cold shutdown.

i) I.C.1 Requirement

The analyses should support development of guidelines that define a logical transition from the emergency procedures into the inadequate core cooling procedure including the use of instrumentation to identify inadequate core cooling conditions.

ATOG Compliance

Inadequate core cooling (ICC) is indicated whenever the incore thermocouples indicate superheat (i.e, temperature greater than saturation temperature for the existing RCS pressure). The operator enters the ICC section of Part I whenever this indication occurs. A loss of subcooled margin will always occur before ICC conditions develop

regardless of the cause. Therefore, Part I requires a check of the incore thermocouple readings whenever a loss of subcooled margin occurs.

Excerpt from ATOG

The following excerpt is from Section III.A of Part I, "Followup Actions for Treatement of Lack of Adequate Subcooling Margin":

> "5.0 IF SUBCOOLING MARGIN HAS BEEN ESTABLISHED, THEN GO TO STEP 11.0, OTHERWISE CONTINUE.
>
> 6.0 IF SUPERHEATED, THEN GO TO ICC SECTION."

j) I.C.1 Requirement

Justify the approach and methodology used to develop the guidelines.

ATOG Compliance

This report is provided as justification for the approach and methodology used to develop ATOG.

5.0 LIST OF REFERENCES

5.1 "Abnormal Transient Operating Guidelines for Oconee Nuclear Station, Unit 3," Babcock and Wilcox, April, 1982

5.2 NUREG-0737, "Clarification of TMI Action Plan Requirements," November, 1980

5.3 "Small Break Operating Guidelines," Babcock and Wilcox, November, 1979

5.4 NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," July, 1979

5.5 NUREG-0899, Revision 1, "Guidelines for the Preparation of Emergency Operating Procedures - Resolution of Public Comments on NUREG-0799," February, 1982

5.6 "Discussion of B&W ATOG Part II in Terms of Validation Performance Standards With a Worst Case Analysis of Risk," Kinton, Inc., September, 1980.

5.7 "Evaluation of Transient Behavior and Small Reactor Coolant System Breaks in the 177 Fuel Assembly Plant," ("Blue Book"), Babcock and Wilcox, May 1979

5.8 BAW 10128, TRAP 2, "FORTRAN Program for Digital Simulation of the Transient Behavior of the OTSG and Associated Reactor Coolant System," August, 1976

5.9 BAW 10098, CADDS, "Computer Application to Direct Digital Simulation of Transients in PWR's With or Without Scram," January, 1975

5.10 TID-4500, CONTEMPT, "A Computer Program for Predicting Containment Pressure-Temperature Response to a Loss of Coolant Accident," June, 1975

5.11 NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," May, 1980

Attachment 2

Babcock & Wilcox
a McDermott company

Utility Power Generation Division
3315 Old Forest Road
P.O. Box 1260
Lynchburg, Virginia 24505-1260
(804) 385-2000

March 14, 1983
582-7108/T1.2
ESC-075

TO: B&W Owners Group
Operator Support Committee

SUBJECT: Resolution of NRC Comments on Oconee ATOG

REFERENCE: B&W Letter, D. A. Napior to Operator Support Subcommittee same subject, dated February 24, 1983

Gentlemen:

B&W met with NRC staff on February 15-17, 1983 to review and resolve the remaining 275 staff comments on the Oconee ATOG. The referenced letter provided a breakdown of the resolution of the NRC comments and a brief description of the five categories of comment disposition. This letter provides the final documentation of comment resolution for your records. The categories listed herein correspond to the categories given in the referenced letter.

Category 1 - Pen and ink changes to ONS-3 ATOG

Attachment A provides a list of the item numbers in this category, a brief description of the concern expressed by Mr. Lyons, and a brief description of the supplement revision agreed to by B&W and Mr. Lyons.

Attachment B provides copies of marked-up pages from the ONS-3 Final ATOG for most of the revisions listed in Attachment A. Revisions to large drawings are described in Attachment A but do not have corresponding copies in Attachment B. The numbers in the Attachment B margins correspond to the item numbers in Attachment A.

Category 2 - Comment to be resolved through followup programs and analysis

No change in comment disposition.

Category 3 - Comment Deleted

No change in comment disposition.

Category 4 - B&W evaluate to determine if additional changes are necessary

B&W has completed a review of the comments in this category and concluded that no additional revisions are necessary. These comments are considered deleted by B&W.

Category 5 - Comment deleted but passed on to PTRB for follow-on review

No change in comment disposition.

Should you have any question or comments, please call.

Very truly yours,

D A Napior

D. A. Napior, Senior Product Manager
Owners Group Engineering Services

DAN/jk

cc: Operator Support Committee

D. H. Williams	- AP&L
W. J. Hall	- CPCo
S. A. Holland	- DPCo
W. M. Johnson	- FPC
T. G. Broughton	- GPUN
D. D. Whitney	- SMUD
J. F. Lingenfelter	- TED
W. Lyon	- NRC
D. Fadden	- INPO

ATTACHMENT A

SUPPLEMENT ITEMS AGREED TO BY B&W

NOTE: Referenced document for all supplement items is the Final ATOG for Oconee Nuclear Station Unit 3, Parts I and II, dated 3/82.

All item numbers correspond to question numbers attached to draft letter, D.G. Eisenhut to D.D. Whitney, dated 10/1/82.

Item No.	Concern	Supplement Revision
13.	Hot leg RTD's may not be valid indication for determining superheated RC conditions.	Revised Part I, Section III A, step 6.0 and deleted substeps 6.1 and 6.2 as shown in attached.
38.	Operator guidance for power runback for SGTR provides only a minimum rate.	Revised Part I, Section III D step 3.2 as shown in the attached.
51.	In previous B&W responses to NRC questions, two revisions were made to Part I, Section III.D, step 20.0, to address two different questions. (Ref: Attachment to letter, D.D. Whitney to D.G. Eisenhut, dated 6/15/82).	Agreed that both revisions are applicable and should be combined. Both previous revisions are attached, with one marked up to show the combined revision.
62.	Literal interpretation of step 6.1 of CP-103 in Part I is confusing.	Revised step 6.1 as shown in the attached.
69.	Part I, Specific Rule 1.0 (HPI) references diesel generators which are not used at ONS.	Revised Specific Rule 1.0 as shown in the attached.
72.	Part I, Specific Rule 3.0 (EFW throttling) could, literally interpreted, lead the operator to overfilling SG.	Revised Specific Rule 3.0, step 3.1, as shown in the attached.
77.	Part I, ICC Section, step 11.3 imposes a time test on the operator. Is this desired?	Agreed that, in Region 4 of ICC, real concern is RCP limits (e.g. bearing temperatures, etc.) which are used without the need for a time test. Therefore deleted step 11.3 (pg. 64) of ICC Section in Part I.

Item No.	Concern	Supplement Revision
125.	Table 2 (Part II, Vol. 1) implies that rods inserted is adequate indication of reactor shutdown and existence of flow is adequate indication of proper ECCS performance.	Revised Table 2 as shown in the attached.
128.	Item 128 consisted of ten parts, all related to Fig. 22 in Part II, Vol. 1. 7 were resolved by deletion. The remaining 3 concerns were: a.) objected to statement under "Corrective Actions for Low Main Feedwater Temperature" that steam production is lost due to covering the tube surface, b.) the precaution statement under Condition 3 did not make sense, c.) objected to statement allowing venting of the containment to relieve containment pressure, i.e., concern over ability to reclose the purge valves.	Revised Figure 22 as follows: a.) deleted section on low feedwater temperature (extreme left portion), b.) in precaution block under Condition 3, revised first line to read: "Although a lot of time exists...", c.) in last precaution listed under P-T diagram (far right) deleted last phrase: "if no radiation exists vent the containment."
139.	ICC instructions in Parts I & II not consistent. In addition, since the RCS is superheated, may not want to adjust SG pressure based on incore thermocouple temperatures.	Revised Part I, ICC Section, step 3.1 and added new steps 3.2 and 5.0 as shown in the attached (existing step 5.0 and rest of ICC Section must be renumbered accordingly). Revised Part II, Vol. 1, pg. 113 as shown in the attached.
142.	Saturation pressures under Time II and Time III of Figure 24a do not agree.	Revised Fig. 24a (Part II, Vol. 1); saturation pressure under Time III to "∿ 2500 PSIG."
155.	Objected to statement in Part II, Vol. 1 (last sentance on pg. 127) that there is no chance for core to become uncovered. Statement was intended to mean as a result of RCP operation, but literally interpreted, implied regardless of any postulated subsequent failures or breaks.	Revised pg. 127 of Part II, Vol. 1 as shown in the attached.

Item No.	Concern	Supplement Revision
168.	Statement on Fig. 31b (Part II, Vol. 1) about shell cooling by steam condensation is not true since shell is hotter than the steam.	Revised statement on Fig. 31b as shown in the attached.
200.	Pressurizer levels on Fig. A-7 (Part II, Vol. 2) are not consistent with Part I.	Revised Fig. A-7 as follows: a.) under "Immediate Actions Summary" in block off main success path: changed " < 80"" to " < 50"" b.) in two places, extreme lower left and upper right: changed " > 80"" to " >100"".
224.	Item 224 consisted of eight parts, all related to Fig. C-3 (Part II, Vol. 2). 5 were resolved by deletion. The remaining 3 were: a.) Several references to bypass ESAS use different pressures, b.) in Mode 3 (sheet 2) first bullet under P-T diagrams contains an incomplete sentance, c.) sheet 1 of 2 is missing. Sheet 1 of 2 in Vol. 2 is really a duplicate of sheet 2, incorrectly titled.	Revised Figure C-3 as follows: a.) all references to ESAS bypass should state at $\sim$ 1700 PSIG for ES channels 1 & 2 and < 900 PSIG for ES channels 3 & 4, b.) at end of first bullet under P-T Diagrams, add "...$\sim$ 50F subcooling." c.) Sheet 1 of 2 is being produced at this time and will be issued by 3/31/83.
234.	Item 234 consisted of 7 parts, all related to Fig. D-9 (Part II, Vol. 2). 6 were resolved by deletion. The remaining concern was an apparent lack of the "loss of secondary inventory control (low)" failure branch.	Revised Fig. D-9 to label the lower left branch "Loss of Secondary Inventory Control (Low)."
241.	Item 241 consisted of 8 parts, all related to Fig. E-4 (Part II, Vol. 2). 5 were resolved by deletion. The remaining three were: a.) pressurizer level requirements not consistent with Part I, b.) actions for isolating steam generators not consistent with Part I, c.) note 3 implies heaters are used to draw a bubble while on HPI cooling.	Revised Figure E-4 as follows: a.) changed pressurizer level requirements in 2 places from " < 80"" to " < 50"" b.) second item under "Immediate Action Summary" on main success path: changed "stop all FW to both SG's" to "Isolate both SG's" c.) changed note 3 as follows: insert new bullet "-Isolate PORV" between existing 2nd & 3rd bullets; changed last bullet to read "Continue Normal Plant Cooldown."

Item No.	Concern	Supplement Revision
253.	Table 4a (Part II, Vol. 1) is not identical to Table F-2 (Part II, vol. 2) as stated on pg. F-30.	Revised Table 4a as shown in the attached.
272.	In ICC Section (Part I), transfer to Region 4 could be accomplished without requiring the high point vents to be opened.	Revised Step 13.0 of ICC Section as shown in the attached.
274.	In ICC Section (Part I), Region 2, literal interpretation of the procedure gets into a closed loop with no exit.	Revised Step 5.3 of ICC Section as shown in the attached.

ATTACHMENT B

#13

6.0 IF INCORE THERMOCOUPLE TEMPERATURE INDICATES SUPERHEATED, THEN GO TO ICC SECTION, OTHERWISE CONTINUE

~~6.1 IF, at any time during the transient T_{hot} RTD indicates superheated conditions, THEN compare T_{hot} RTD indication with incore T/C temperatures.~~

~~6.2 IF BOTH T_{hot} RTD and incore TC temperatures indicate superheat, THEN go to ICC Section, otherwise continue.~~

7.0 IF THERE IS PRIMARY TO SECONDARY HEAT TRANSFER IN BOTH SGs, THEN GO TO CP-103, OTHERWISE CONTINUE.

P The RCS is saturated. A small break is indicated.
P Cooldown with the SGs can be performed while HPI
S maintains RCS inventory.

8.0 IF THERE IS PRIMARY TO SECONDARY HEAT TRANSFER IN ONLY ONE SG, THEN GO TO LACK OF HEAT TRANSFER SECTION III B, OTHERWISE CONTINUE.

9.0 IF The CFTs HAVE EMPTIED, THEN GO TO CP-101, OTHERWISE CONTINUE.

P The Core Flood Tanks emptying is an indication of a major
LOCA, CP-101 provides instructions for long-term core
P cooling following a major LOCA. Do not go to Section
III.B. Primary to secondary heat transfer will be lost
S and cannot be regained.

10.0 IF THE CFTs HAVE NOT EMPTIED, GO TO LACK OF HEAT TRANSFER SECTION III B.

III D

SGTR

FOLLOWUP ACTIONS FOR SG TUBE RUPTURE

1.0 IF THE REACTOR HAS TRIPPED, GO TO STEP 4.0, OTHERWISE CONTINUE.

REACTOR TRIP HAS NOT OCCURRED

2.0 INITIATE HPI IF REQUIRED.

2.1 IF pressurizer level is being maintained by the makeup system, THEN go to step 3.0, otherwise continue.

2.2 Manually initiate HPI as required to maintain pressurizer level greater than 100". (See Specific Rule 1.0)

2.3 IF pressurizer level cannot be maintained, THEN trip the reactor and go to step 4.0, otherwise continue.

3.0 SHUTDOWN REACTOR.

3.1 Isolate letdown (HP-5)

3.2 Immediately begin power reduction at ~~greater than 5% per minute~~ as fast a rate as can be controlled. #38

3.3 If reactor trip occurs during runback, go to Section I and perform Section II, VSSV.

3.4 Make local survey of main steam line to confirm high radiation alarms and identify the tube ruptured SG.

3.5 At less than 20% reactor power:

a. Place the TBVs in manual.

b. Open TBV's - Unload and "trip" turbine/generator.

c. Trip reactor.

d. Properly place TBVs back into auto.

FRO(ATTACHMENT TO LETTER, (D. WHITNEY
TO D.G. EISENHUT, DATED 6/15/82

5. Cooldown With DHRS

Question: Could you provide more specific guidance on how to cooldown the loops after DHRS start?

Response: Part I has been modified to assist the operator in making the transition to DHRS. Section III D, Step 20 is changed to:

20.0 Continue cooldown per procedure OP/3/A/1102/10 using only one SG. Observe the following precautions:

20.1 Steam the tube ruptured SG as necessary to prevent filling the SG.

20.2 When steaming is no longer possible drain the SG as necessary to the condenser to prevent filling the SG.

20.3 Depressurize the RCS as close to subcooling margin line as possible to minimize the tube leak rate driving force.

20.4 Feed SG's as necessary to maintain tube-to-shell ΔT <150F.

20.5 Maintain powdex cells in operation to remove activity from condensate.

#51

20.6 Continue cooldown and drain RCS as soon as possible to stop the leak.

FROM ATTACHMENT TO LETTER D.D. WHITNEY TO D.G. EISENHUT, DATED 6/13/82

Section III D

Step 20.0

Question: Provide continuity between Section III D and termination of the tube leak (i.e., RCS Draining).

Response: The present step transfers the operator to procedure OP/3/A/1102/10. This procedure has the operator run the RCP's and decay heat removal system in parallel to cooldown to 185 F. It will then direct him to drain the RCS. Step 20.1 is being added to Section III D to reinforce this objective.

Revision: Added Step 20.1 to III D.

PLANT IS COOLING DOWN WITH ONE SG ISOLATED

19.0 CONTINUE COOLDOWN WITH APPLICABLE LIMITATIONS.

19.1 When RCS pressure and leak rate decrease and RCS inventory and subcooling can be maintained by the MU system, stop the HPI system and establish normal MU control.

19.2 Continue depressurization and cooldown at the maximum attainable C/D rate without exceeding 100 F/hr using the SG without the tube rupture.

19.3 Cooldown on the tube ruptured SG if the other SG is not operable.

19.4 Decrease the RCS pressure as required to remain as close as possible to the minimum subcooling margin line.

19.5 If an unisolable steam line break has occurred, upon reaching 400F determine the tube to shell ΔT. If ΔT is less than 150F, continue the cooldown.

19.6 If tube to shell ΔT exceeds 150F, stop cooldown. Feed the steam leaking SG as necessary (approximately 100 GPM) through the MFW nozzles to maintain tube to shell ΔT less than 150F. When ΔT is less than 150F, continue cooldown while maintaining ΔT less than 150F.

19.7 Notify Health Physics or Technical Support personnel to run PT/O/A/260/3, (Condenser Iodine Partition Factor Test).

19.8 For removal of activity from the condensate system, maintain in service the minimum number of powdex cells required for current condensate flow.

20.0 CONTINUE NORMAL COOLDOWN PER PROCEDURE OP/3/A/1102/10 USING ONLY ONE SG.

20.1 Continue cooldown and drain ~~[illegible]~~ RCS as soon as possible to stop the leak.

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The tube rupture SG has been identified. The RCS is subcooled and the pressurizer is controlling RCS pressure.

6.0 WHEN THE RCS BECOMES SUBCOOLED, THEN START A RCP.

6.1 Determine if subcooled conditions exist by using ~~comparing~~ exit T/C's and hot leg RTD's. #62

6.2 Preferably start RCP B1 or B2.

7.0 IF THE RCS REMAINS SUBCOOLED AFTER STARTING THE RC PUMP, THEN GO TO CP-105, OTHERWISE CONTINUE.

8.0 IF FOR ANY REASON THE RCS BECOMES SUPERHEATED, THEN GO TO SECTION ICC.

9.0 IF THE RCS REMAINS SUBCOOLED DURING THE NATURAL CIRCULATION COOLDOWN, THEN GO TO CP-105, OTHERWISE CONTINUE.

10.0 WHEN THE RCS DEPRESSURIZES TO LESS THAN 150 PSIG, THEN CLOSE ALL HIGH POINT VENT VALVES (RC-155, RC-156, RC-157, RC-158, RC-159, and RC-160).

11.0 WHEN LPI FLOW HAS BEEN IN EXCESS OF 1000 GPM IN EACH INJECTION LINE FOR AT LEAST 20 MINUTES, STOP HPI PUMPS AND CONTINUE, OTHERWISE GO TO STEP 14.

12.0 TRANSFER LPI SUCTION TO RB SUMP.

12.1 WHEN the BWST lo-lo-level alarms (minimum time 1/2 to 1 hour), THEN transfer LPI suction to RB sump. Manual override buttons must be depressed when making the following valve manipulations.

a) Verify RB sump suction valves, outside containment, LP-19 and LP-20 are open.

b) Close BWST outlet valves, LP-21 and LP-22, to prevent pumping BWST dry.

13.0 GO TO STEP 16.7.

SPECIFIC RULES

1.0 INITIATE HPI.

1.1 Verify indicated HPI flow is equal to or greater than the dotted line in Figure 1.

1.2 If HPI flow cannot be verified in both loops, open the cross connect valves for the HPI header, HP-409 and HP-410.

1.3 IF one HPI pump fails to start, THEN perform the following actions:

~~a. Verify the makeup pump is lined up to receive power from the operating diesel generator.~~

a ~~b~~. Establish a pump suction flow path from the BWST.

b ~~c~~. Verify the letdown storage tank outlet valve is closed, HP-23. #69

~~d. Adjust loads as necessary on the operating diesel generator to supply power to the makeup pump (about 530 KW).~~

c ~~e~~. Place the makeup pump in service.

1.4 IF HPI flow cannot be increased to at least the value of dotted line in Figure 1, THEN maintain the maximum attainable HPI flow while investigating the HPI system.

1.5 IF the HPI system is not operating properly, THEN refer to the SAD section.

SPECIFIC RULES

3.0 PROPERLY THROTTLING EFW.

3.1 IF natural circulation has stopped AND SG level is below appropriate level, THEN ensure full EFW flow. Do not throttle EFW until natural circulation is verified or appropriate level is obtained.

#72

3.2 IF RC temperature is to be stabilized, THEN throttle EFW to maintain SG pressure at less than 100 psig below the turbine header pressure setpoint. (e.g. throttle EFW to maintain SG pressure above 910 psig after a reactor trip when the turbine header setpoint has been biased to 1010 psig).

3.3 IF a cooldown is required, THEN throttle EFW as necessary to limit the cooldown rate to less than the maximum allowed 100F/hr.

3.4 Maintain continuous EFW flow until the appropriate level setpoint is reached (see Specific Rule Number 4.0). Do not allow the SG level to decrease if level is still below the appropriate level.

3.5 IF the EFW system is not operating properly, THEN refer to the SAD section.

PLANT STATUS INDICATOR	OPERATOR ACTION REQUIRED
1. Turbine Trip and/or Reactor Trip	• Verify that all control rods (except APSR's) are on bottom; verify power decreasing. • Manually trip both the reactor and turbine. • If one or more control rods are not fully inserted begin boration (at a later time a stuck rod may be driven in). • Isolate letdown bypass of block orifice (if on high flow bleed cycle at time of trip).
2. ES Actuation	• Confirm that the HPI and LPI (<500 psig) are started. • Verify that at least one train in each ECCS is on (pump on). If not, try to start ECCS manually. #125 • Verify, by review of ECCS flow indication, that proper flow exists in the injection lines. • Confirm containment isolation (for high containment pressure) (non-essential on low RCS pressure). • Confirm containment cooling systems start (on high containment pressure). • Trip RC Pumps on loss of subcooling margin. • If containment isolation has stopped cooling water to the RC Pumps, either reinstate or trip pumps.
3. Loss of Offsite Power (LOOP)	• Verify that at least one Keowee generator starts and automatic loading is completed. If the Keowee unit connected to the 13.8 KV buss fails to start, manually transfer the buss to the running Keowee unit.

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BASIS FOR ACTION

manually trips the reactor and turbine and should verify that the fission process is shutdown by ensuring the rods are fully inserted and that power is decreasing.

After reactor or turbine trip, the operator ~~should ensure that the fission process is shutdown. The simplest method is to ensure the rods are fully inserted; if not, the operator should manually trip both the turbine and reactor and ensure that a rapid decrease in neutron flux has occurred.~~ Compensation for a stuck rod will have to be by boration to maintain a subcritical margin when the plant is stabilized or plant cooldown is required.

When a reactor trip occurs, Tave will decrease due to the loss of core fission power, and an outsurge from the pressurizer will be caused by the contraction of the reactor coolant. The MU control valve will open to increase MU in response to a decrease in pressurizer level. To minimize the potential for a loss of pressurizer level and/or indication, the operator should manually isolate the letdown bypass of block orifice. It is not necessary to isolate "normal" letdown.

When an ES actuation occurs, the operator should assure that at least one train is operative (one pump on) and that proper flow is present. At this point, HPI/LPI flow balancing is not required, but can be done later.

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ure).

Upon loss of normal and standby power sources, the two 4160 volt Engineered Safeguard buses are energized, powered by at least one Keowee generator. Bus load shedding, bus transfer to the Keowee generators, and pickup of critical loads is automatic. When a loss of power occurs, the operator should ensure that at least one Keowee generator starts and that loading is completed, and he should try to start the other. (See ATOG Guidelines, Part II, Section 2, "Loss of AC Power," for details about equipment which is automatically loaded and for equipment which must be manually started.)

SECTION ICC

FOLLOWUP ACTIONS FOR INADEQUATE CORE COOLING

1.0 INITIATE HPI & LPI.

1.1 See Specific Rule 1.0.

1.2 IF LPI is delivering flow, THEN increase LPI flow to maximum.

2.0 INCREASE SG LEVELS TO 90-95%.

3.0 LOWER SG PRESSURE TO INDUCE HEAT TRANSFER.

3.1 Depressurize SG(s) while maintaining level(s) to achieve secondary T-sat 90 to 110F lower than T-sat for the existing RC pressure. ~~incore T/C temperature and maintain this ΔT.~~

3.2 when heat transfer restored, continue to depressurize SG(s) as necessary to achieve a 100F/hr RCS cooldown rate.

4.0 ENSURE CORE FLOOD TANK ISOLATION VALVES (CF-1 and CF-2) ARE OPEN.

5.0 IF RCS PRESSURE INCREASES TO 2300 PSIG, THEN OPEN THE PORV (RC-66). CLOSE THE PORV WHEN RCS PRESSURE DECREASES TO 100 PSI ABOVE SG PRESSURE.

~~5.0~~ 6.0 TAKE ACTION BASED ON FIGURE 3.

6.1 ~~5.1~~ Average the five highest reading incore T/C temperatures.

6.2 ~~5.2~~ Determine which region of Figure 3 that the RCS is in based on Step 5.1.

6.3 ~~5.3~~ Using the region determined in Step 5.2, take action according to the following table.

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REGION	ACTION
1	Go to CP-103
2	Continue Step 1.0 - ~~4.0~~ 6.0 above
3	Go to Step ~~6.0~~ 7.0
4	Go to Step ~~11.0~~ 12.0

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outlined below and are based on where the RC pressure-incore thermocouple temperature (P-T/C) combination corresponds to the curves of Figure 29.

If the P-T/C combination is between the saturation curve and Curve 1 superheated conditions exist and the operator should:

1. Verify emergency cooling water is being injected through all HPI nozzles into the RCS,
2. Initiate any additional sources of cooling water available such as the standby makeup pump,
3. Verify the steam generator level is being maintained at the emergency level,
4. If steam generator level is not at 95% of operating range, raise level to the 95% level,
5. If the desired steam generator level cannot be achieved, actuate any additional available sources of feedwater.

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6. Reduce SG pressure to achieve secondary Tsat ~ 100F lower than Tsat for the existing RC pressure. If heat transfer is restored, continue SG pressure reduction, as necessary, to achieve a 100F/hr RCS cooldown rate. ~~Establish 100F/hr. cooldown of RCS via steam generator pressure control until secondary steam saturation temperature is 100F below the incore thermocouple temperature~~.
7. Open core flooding line isolation valves if previously isolated.
8. If RC pressure increases to 2300 psig, open the pressurizer PORV to reduce RC pressure and reclose PORV when RC pressure falls to 100 psi above the secondary pressure.

should be run for cooldown as long as at least one OTSG is available as a heat sink. Natural ciruclation will not start when there is not enough water in the RCS. The reasons for this exception, which goes against other requirements that do not permit RC pump operation when the subcooled margin is lost, are that the RCS should be depressurized and placed on the decay heat system before the BWST runs dry (to avoid HPI recirculation from the sump) and that the several "bumps" have consumed time. The one hour time limit has allowed the decay heat load to drop sufficiently so that the HPI system is now capable of adding enough water to make up the flow out of the break and remove all of the heat, including any additional break flow due to RCP operation. ~~There is no chance for the core to become uncovered when the RC pumps are run at this time when the HPI system is working.~~

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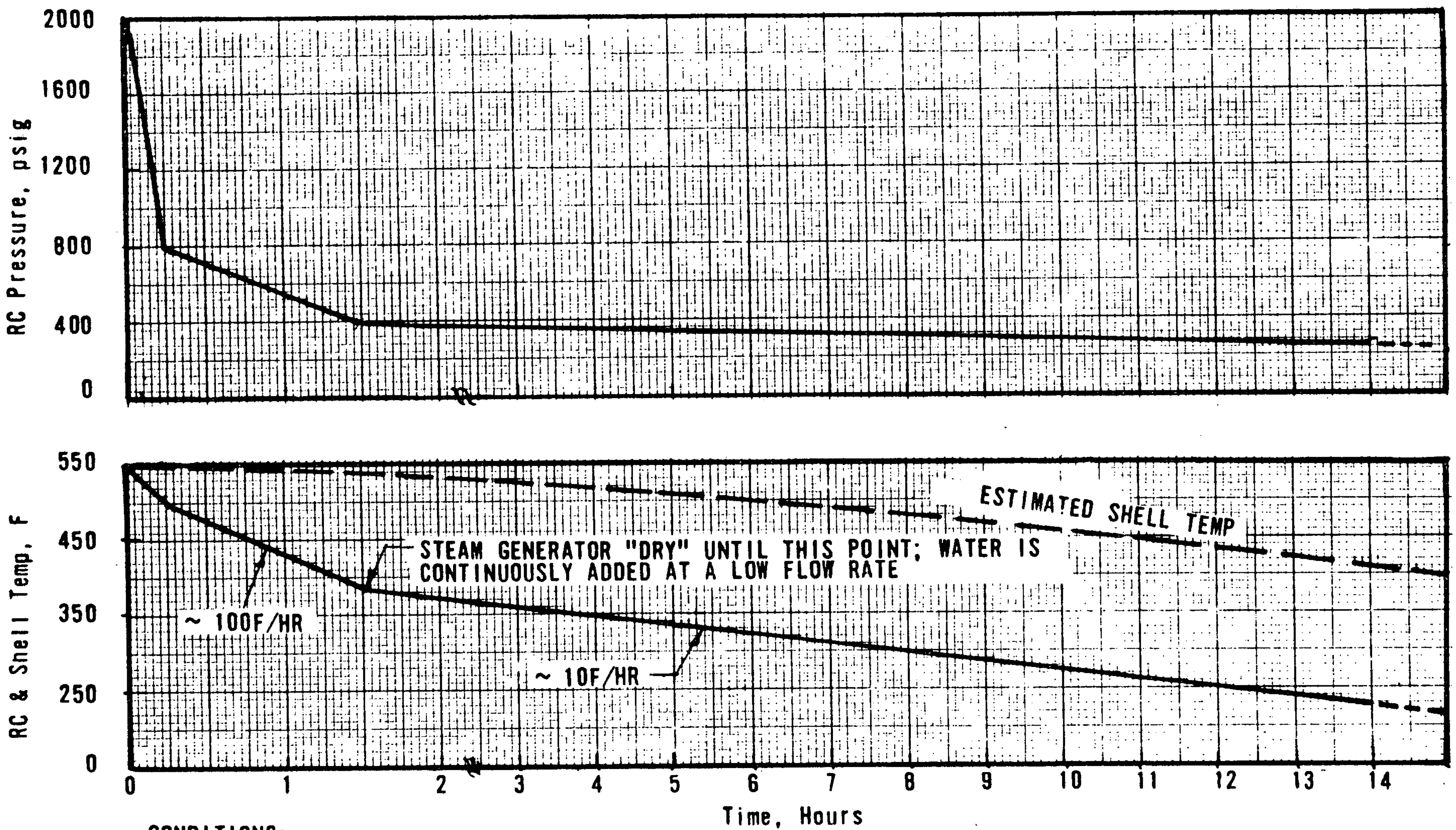
Figure 31b COOLDOWN ON ONE STEAM GENERATOR (STEAM PRESSURE NOT CONTROLLED)



CONDITIONS:

- RC PUMPS ON OR OFF (PROBABLY ON)
- STEAM LEAK IN GENERATOR; STEAM PRESSURE IS AMBIENT
- SLOW FEEDING OF GENERATOR BEGINS AT ~ 1 1/2 HRS - IT IS DOUBTFUL THAT LEVEL WILL BUILD FOR SEVERAL HOURS; LOWER SHELL WILL NOT BE COVERED FOR SOME TIME; SHELL COOLING IS BY STEAM ~~CONDENSATION~~ CONVECTION

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Table 4a HOW TO DISTINGUISH LOCA'S FROM OTHER TRANSIENTS

Unique Characteristics of LOCA's

- Rapid system depressurization to saturated conditions with little or no change of reactor coolant temperature (characteristic of all but the very smallest breaks)
- Sustained saturation (HPI does not return the reactor to a subcooled state within 5-10 minutes after actuation)
- Containment radiation (only for breaks in containment)

  NOTE: A steam or feed line leak inside containment will cause high pressure, temperature and humidity but will not cause high radiation.
- Steam pressure, feed flow and steam generator level do not indicate overcooling (this helps to differentiate LOCA's from overcooling transients)
- High steam line radiation alarms (tube leaks only)
- Low letdown storage tank level (in the absence of all of the above, this indicates a leak outside the containment)

NOTE: LOCA's CAN BE DIFFICULT TO DETECT, ESPECIALLY IF THE BREAKS ARE SMALL. ~~THEY CAN OCCUR INSIDE THE CONTAINMENT AND STEAM GENERATOR TUBE LEAKS ARE LOCA'S.~~ IF THERE IS ANY DOUBT THAT AN ACCIDENT IS A LOCA, ASSUME THAT IT IS AND TAKE APPROPRIATE LOCA ACTIONS UNTIL CLEARLY PROVEN OTHERWISE. THE GENERAL ACTIONS INCLUDE HPI COOLING, RC PUMP TRIP, AND COOLDOWN TO COLD CONDITIONS.

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INCORE THERMOCOUPLE TEMPERATURE IS IN REGION 4

11.0 START ALL RCPs

11.1 Starting interlocks should be defeated if necessary.

11.2 Do not defeat the overload trip circuit.

~~11.3 IF low pressure service water is lost AND not restored to the motor within 30 minutes, THEN trip the RC pump.~~ #77

12.0 LOWER SG PRESSURE TO INDUCE HEAT TRANSFER

12.1 Depressurize the operative SG(s) as quickly as possible. Do not go below the minimum steam pressure necessary to power the steam driven EFW pump unless one of the following is available:

a) Steam from another unit.

b) Steam from aux. boiler.

c) Both motor driven EFWPs.

13.0 DEPRESSURIZE THE RCS

13.1 Open or verify open all high point vent valves, RC-155, RC-156, RC-157, RC-158, RC-159, and RC-160.

13.2 Open the PORV (RC-66) and PORV block valve (RC-4) and leave open.

13.3 Depressurize the RCS until LPI restores core cooling.

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14.0 WHEN incore thermocouple temperature returns to the saturation temperature for the existing RCS pressure, THEN continue with Step 15.0.