PDR-016

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

OCT 14 1983

Mr. Steven C. Sholly
Technical Research Associate
Union of Concerned Scientists
1346 Connecticut Avenue, NW
Suite 1101
Washington, DC 20036

IN RESPONSE REFER
TO FOIA-83-530

Dear Mr. Sholly:

This is in further response to your letter dated September 8, 1983, in which you requested, pursuant to the Freedom of Information Act (FOIA), that NRC make 42 listed records publicly available at the NRC Public Document Room (PDR).

By letters dated September 26 and October 3, we provided partial responses to your request and informed you that the staff was searching for and reviewing the remaining requested records.

At this time, we are making the records identified at the following numbers of your FOIA request available at the PDR. These records will be filed in PDR folder FOIA-83-530 under your name.

3	25
8	26
12	35
15	37

The staff is continuing to search for and review the additional records subject to your request. We will notify you as search and review are completed.

Sincerely,

J. M. Felton, Director
Division of Rules and Records
Office of Administration

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON D C 20555

JUN 11 1981

MEMORANDUM FOR: Malcolm Ernst, Assistant Director of Safety Technology, NRR

FROM: Bernard Fourest

SUBJECT: REVIEW OF ECCS ACTUATIONS ON U.S. PWRs

You will find enclosed for your consideration a report on safety injection (SI) actuations at US operating PWRs since their first criticality to December 1980. The report focuses on unnecessary challenges of the safety injection system. A high number of unneeded SI can potentially lead to two adverse effects: an increase in the usage factor of the SI nozzles that could become unacceptable before the normal end of life of the plant; and an operator becoming accustomed to considnr every SI initiation as inadvertent or spurious and, accordingly, to terminate the SI before a comprehensive evaluation of the causes of the occurrence has been performed.

Combustion Engineering designed reactors seem to have a good performance record with regard to these two areas of concern.

Babcock and Wilcox designed reactor had experienced a large number of manual SI initiation due to a tendancy of the operators to use the safety injection system for presurizer level recovery after almost each reactor trip. This action has been found as not necessary, and the B&W reactor operators have been recently instructed to avoid routinely challenging the SI. This problem is thought to be resolved.

Westinghouse designed reactors experience an important rate of unnecessary SI actuations. This is thought to be mainly due to the SI initiating parameters on the secondary system that are part of the steam line break detection system. These secondary side SI initiating parameters are unique to Westinghouse designed reactors. At least one licensee has submitted a proposal to modify the steamline break protection system that would reduce the number of SI initiating parameters. We are also aware that Westinghouse is offering this modification for future units. The new system has the potential to reduce the number of unnecessary SIS challenges. If the NRC staff determines that this modification has no adverse effect on the plant safety, we would recommend that this modification be backfitted on the operating Westinghouse reactors that experienced the highest number of inadvertent SI such as Zion 1 and 2, D.C. Cook and Salem.

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JUN 11 1981

The report also offers some recommendations to improve the emergency procedures and the maintenance and test procedures of the SI system and its actuation logic. These recommendations could be implemented under the TMI Action Plan.

Bernard Fourest

cc: DEisenhut, NRR
SHanauer, NRR
CMichelson, AEOD
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SURNAME ▶	WDMeinke:kd	PJConvel	Acting				
DATE ▶	06/19/81	06/15/81	06/ /81				

OPERATING EXPERIENCE REPORT ON SAFETY INJECTION (SI) ACTUATIONS ON U.S. PWRs

I SCOPE

The purpose of this study is to review some aspects of the operating experience of U.S. PWRs with safety injection initiation. A special emphasis is put on the unnecessary challenges of the safety injection system. This problem has first been recognized in an ACRS report NUREG-0572, "LER Review 1976-1978," Item D.XXIII. The areas of concern with an excessive number of unnecessary SI initiations will be addressed and the behavior of the various units will be reviewed according to their NSSS vendors. The main cause of unnecessary SI challenges will be traced and some recommendations will be suggested to improve the situation.

II DATA BASIS

As a first step an LER search was performed on the ORNL computer file with the key word "safety injection" from 1969 to October 1980. This search came out with 582 LERs that were screened for SI automatic or manual actuation. Ninety-four such LERs were identified, five on Babcock and Wilcox (B&W) reactors, seven on Combustion Engineering (CE) reactors and eighty-two on Westinghouse (W) reactors.

As a second step, the licensee's answers to the B&O task force questions requested just after the TMI-2 accident were reviewed. The questionnaire sent to all W and CE operating reactor licensees asked for ECCS experience. The licensee's responses vary widely in the degree of details provided. Some sent a complete set of reports for each SI occurrence while others just gave a number of SI actuations without even indicating the dates of occurrence. This information has been updated by a review of the "Grey Book" data from May 1979 to November 1980. Finally we identified a total number of 165 SI for W plants and 24 for CE plants.

Unfortunately, the B&O task force did not require the B&W licensees to report on their past experience with ECCS actuation. The only way we had to get the information was by informal means through the Resident Inspectors and the Project Managers. Arkansas 1, Crystal River, Oconee 1, 2, 3, and Rancho Seco are the only B&W units on which we have been able to collect usable data.

III SI CATEGORIZATION

The various SI occurrences have been sorted according to the following categories:

1. Transients or accidents assessed in the FSAR studies as requiring SI actuation.

   This includes small break LOCA (PORV stuck open and RCP seal failure), steam generator tube failure, and gross over cooling or over feeding of the steam generator. Typical of these two last events are steam dump valve failure to close after a reactor turbine trip, spurious opening or failure to close of a mean steam relief valve, and failure to control the auxiliary feedwater flow properly after a reactor trip.

2. Spurious actuations.

   We call spurious those SI actuations that did not result from the physical parameters that trip the SI signal actually reaching a trip setpoint. Typical of these spurious actuations are failure in the SIAS actuation logic, or loss of more than one vital or instrument bus, or loss of power on a channel while another one was tripped for maintenance.

3. Inadvertent actuation. This category includes the occurrences when the physical parameters aimed to trip the SI system actually did reach a trip setpoint but the actuation did not result from a transient requiring safety injection. Typical of this category are water hammers in the steam feedwater system that trigger the high steam ΔP setpoint between two steam lines, or spurious closure of one main steam isolation valve. We have also included in this category all the manual actuations on B&W plants due to the operator attempts to recover the pressurizer level after reactor trips.

4. Unknown cause.

   This category includes all the events with insufficient information collected to be classified in one of the previous categories.

For each unit grouped by vendor, Table I gives the total number of SI actuations experienced since the first criticality, the average frequency of actuations per reactor year, and the number of SI actuations relevant to the four previous categories. The two last columns identify the numbers of SI actuations that occurred during test or maintenance work as well as those which involve a personnel error. A personnel error might be a proximate cause as well as a remote cause (i.e., the personnel error results in a transient that causes ECCS initiation).

In the following we will use "unnecessary" or "unneeded" SI for both spurious and inadvertent SI.

IV. SI ACTUATION FREQUENCY

The frequency of SI actuation per reactor year ranges from 0 (Point Beach 2, Calvert Cliffs 2) to 5 (Crystal River). The highest average frequency of SI actuation is for B&W plants (2.6 per reactor year), then for Westinghouse plants (0.84 per reactor year). CE plants have an average SI frequency of 0.5 per reactor year.

We can assume that most of the SI actuations categorized above as "unknown cause" were either spurious or inadvertent. Otherwise it is likely that they would have been reported by an LER. If we make this assumption, the percentage of needed SI (first category, those due to transients or accident) is 13% for W reactors, 50% for CE reactors and 13% for B&W reactors. These numbers reveal a high rate of unneeded SI, especially for B&W and W plants.

V PROBLEMS OF CONCERN WITH UNNEEDED SI

We have identified two main areas of concern with high numbers of unneeded SI actuation.

The first concern is related to the usage factor of the reactor coolant system and appurtenances especially the SI nozzles. Upon initiation of safety injection when the reactor is at power or hot standby the HPI pumps inject cold water from the borated water storage tank into the hot primary system. That creates a thermal shock that results in thermal stresses in the primary pressure boundary, especially at the injection point, i.e., the SI nozzle. For most PWRs, 40 to 50 such SI thermal transients are taken into account in their design. In the fatigue analysis performed at the design stage, these thermal transients are combined with other thermal transients such as reactor scrams to demonstrate that the usage factor for all parts of the reactor coolant system will remain below one, for the whole expected life of the plant. Forty to fifty safety injections for the whole life of the plant correspond roughly to one SI actuation per year. Accordingly one can think that the situation at Zion 2, for instance, which experienced 24 SI in eight years of operation, is not acceptable. However, there is a lot of conservatism in the design fatigue analysis and each actual SI actuation on a specific plant does not result in a thermal transient similar to those assumed in the design fatigue analysis. The actual thermal stress depends on the difference in temperature between water in the BWST and the RCS. It also depends on the duration of the injection phase. It is worthwhile to note that for those plants that have intermediate pressure shutoff head ECCS pumps (1500 psi), cold safety injection water does not enter the RCS unless the RCS pressure is reduced significantly below the normal operating pressure range. Therefore, for those plants, most unneeded SI do not result in significant thermal stresses on the RCS.

ASME standards require the licensees to keep track of the thermal transients experienced by the primary pressure boundary during the life of the plant and to calculate its usage factor periodically. However, this information is reported to the NRC on a voluntary basis. In its last reportable occurrence report (LER 80-26/99 x-0) related to an inadvertent safety injection, Commonwealth Edison stated that the current usage factor for the SI nozzles of Zion 2 was only 0.1472.

It is not deemed necessary to require all licensees to provide the NRC staff periodically with usage factor calculations. However, it could be beneficial that the NRC staff be allowed to review the assumption and the accuracy of the usage factor calculation for those plants that experienced a significantly higher than average number of SI (for instance, three SI in a single calendar year). Therefore, we recommend that the licensees whose plants will experience three or more SI actuation in a single calendar year be required to report their usage factor calculation to the NRC at the end of that calendar year.

The second area of concern is probably the major one. It relates to the operator behavior. If most SI are unnecessary, the first reaction of the operator upon an SI signal is likely to consider it as spurious or inadvertent and to take action to terminate SI before borated water will be injected into the RCS. It is noteworthy that for most plants SI injection results in the RCS boration; that means an outage from several hours to one day and the corresponding loss of profit for the utility. Therefore, there is a natural tendency to terminate spurious SI as soon as possible. After the Three Mile Island accident the need to verify the safe status of the plant thoroughly before terminating SI has been greatly emphasized. All licensees were required to include a specific set of SI termination criteria in the emergency procedures. This provision was thought to have solved the problems. However, since Three Mile Island, at least on two instances (Surry 2 August 26, 1980 and H. B. Robinson January 29, 1981) SI was terminated in a very short period of time (less than two minutes) hardly consistent with the time needed for a thorough check of the SI termination criteria (similar instances of such action can be found on foreign reactors). Moreover, the analysis of the H.B. Robinson event (January 29, 1981) revealed that, though the SI termination criteria required by the NRC have been included in the LOCA emergency procedures, the operator would not use them unless he has determined that the SI was not spurious and he has entered the proper emergency procedures. But apparently there is no specific criteria to determine whether an SI is spurious, inadvertent or really needed. And the operator has to rely upon judgment and experience.

Therefore, there is an obvious need to develop and provide all plant operators with a sort of diagnostic help based on a definite set of criteria to determine whether an SI is needed. In addition, there is the need of a specific procedure for recovery from an unneeded SI in order that subsequent operator actions would not incapacitate further possible SI automatic initiation in the course of the following event sequence.

VI ANALYSIS OF PLANT BEHAVIOR

a. CE Plants

Table 1 shows that the average SI actuation frequency for CE plants is 0.5 per reactor year with a maximum of 1.5 per reactor year at Arkansas 2 and St. Lucie. These numbers are acceptable and do not pose any problem with regard to the RCS usage factor. Half of the SI were needed. All of them were due to secondary transients that resulted in overcooling or over feeding. Therefore, the rate of unneeded SI is low and the risk of operators becoming accustomed to terminating an SI swiftly is not deemed important.

b. B&W Plants

As shown in Table 1, B&W reactors experienced the highest rate of SI actuation and the highest rate of unneeded SI. However, the great majority of these SI were manually initiated after reactor trips to recover the pressurizer level. B&W reactors have low water inventory steam generators. Accordingly, the primary system is very sensitive to secondary side perturbations and almost every reactor trip results in a sharp pressurizer level drop. All B&W reactors except Davis Besse use High Pressure Safety Injection (HPSI) pumps as make-up pumps. One of these pumps is dedicated for normal make-up as well as one injection line that is designed accordingly. The three other injection lines are only designed for safety injection. Upon almost every reactor trip the operators used to turn on one more HPSI pump and to open the throttling valves on some supplemental injection lines. This practice raised the concern some years ago about the usage factor on the SI nozzles that were not designed for normal make-up. It was demonstrated that this operator action was not necessary to recover the pressurizer level after a reactor trip (memo from H. Denton to C. Michelson, February 13, 1981, "NRR Response to AEOD Recommendation on the Arkansas 1 LOOP Event"). In 1975 Arkansas 1 modified its scram procedure in removing the instruction to use the safety injection lines to recover the pressurizer level after each reactor trip. Since that date Arkansas 1 has not experienced any SI actuation for this reason.

After Three Mile Island all other B&W operators were instructed not to initiate SI manually after a reactor trip. Since the end of 1979 it seems that the B&W reactor operators have complied with this recommendation.

If we set apart this problem which now appears to have been solved, B&W reactors appear not to have experienced a lot of spurious SI.

c. Westinghouse Plants

The average SI actuation frequency in W plants is 0.84 per reactor year, but this average number covers a large variety from 0 to more than 3 SI per reactor year. Zion units 1 and 2, Salem 1 and Beaver Valley 1 are the plants that experienced the largest numbers of SI. For those plants the usage factor on the SI nozzle might be a problem to look at in the coming years if the situation does not improve.

On an average basis, W plants also have a high rate of unneeded SI. Only 13% of the SI were really needed (small break LOCA or overcooling transients). Therefore, the potential for the operator becoming accustomed to spurious or inadvertent SI is a problem for those plants.

A reason for this difference in behavior of $\underline{W}$ units with other vendor units is the fact that $\underline{W}$ designs provide more signals for initiating SI. Current CE and B&W designs provide only two initiating parameters: low reactor pressure (LRP) and high containment pressure (HCP) while $\underline{W}$ designs provide in addition two or three initiating parameters from the secondary system such as high pressure difference ($S\Delta P$) between main steam lines or high steam flow (HSF) in coincident with low-low average primary temperature (L Tavg) or low steam pressure (LSP). These secondary side initiating parameters are provisions for early detection of a steam line break and for borated water injection to avoid re-criticality in the first minutes of the accident. Table 2 provides the ECCS initiating parameters and setpoint for each $\underline{W}$ unit; this information is excerpted from NUREG-0611.

Table 3 is an attempt to correlate the SI actuation frequency with the number of initiating parameters. It is clear from this table that the greater the number of initiating parameters, the higher the number of SI. However, some plants like H.B. Robinson and Turkey Point 3 and 4, the design of which includes the five initiating parameters, experienced a low number of SI and a plant like Farley with only four initiating parameters experienced a higher than average number of SI.

Therefore, looking for a reason for these discrepancies, we listed the units according to their age (Table 4). It can be seen on this table that the nine units that came on line before 1973 have a lower than average SI frequency and that all units (except three) that came on line since 1973 have a higher than average SI frequency. It might be concluded from these considerations that plants of more recent vintage might have less margin between the operating condition and the condition that requires ESF actuations.

To look further on the influence of various initiating parameters we have provided the matrix of Table 5. The columns in Table 5 refer to SI categories as defined above in Section III. The lines in Table 5 refer to the SI initiating parameters. Manual actuation and SIAS logic problems that resulted in SI actuation were also listed in the line of this table. The high containment pressure signal does not appear because it is our understanding that it never initiated any SI on Westinghouse plants. The major contributor to needed SI was the LRP signal (45%). The major contributors to spurious SI were the HSF and L Tavg signals (26.5%) and those SI initiated in the SIAS logic itself (27.9%) (logic failure or loss of vital buses). Eighty percent of inadvertent SI resulted from the $S\Delta P$ signal.

If one removes the 36 SI for which the initiating parameter is not known from the data base, about 60% of the remaining SI were unnecessary and actuated by secondary side parameters.

As stated above, these secondary side initiating parameters are intended to detect steam line break accidents and to avoid recriticality by boron injection in the RCS. But it is not obvious that so many parameters are absolutely necessary for this purpose. Actually we are aware that Duquesne Light submitted a license amendment for Beaver Valley 1 to incorporate a new steamline break protection system design. The new system includes the suppression of the high steam ΔP signal, the high steam flow signal in coincidence with either low steam pressure or low-low Tavg and their replacement by a low steam pressure in any loop set at 500 psig. The NSSS designer made the statement that the new system is as comprehensive for protection as the former system and that it is expected to be more reliable. If in its review of the license amendment, the NRC staff concurs with this statement and concludes that the modification has no adverse effect on the safety of the plant, this simplification of the safety injection actuation system would certainly result in a significant decrease in the number of unneeded SI initiations and subsequently would ease the problem of operators becoming accustomated to spurious SI.

Therefore, if the NRC staff does not oppose the modification proposed for Beaver Valley, we would recommend that the same modification be applied to other units.

VII PERSONNEL ERROR AND TEST OR MAINTENANCE

Table 1 provides, for each W and CE plant, the number of SI actuations that involve a personnel error as well as those that occurred during test or maintenance operations. The data gathered on B&W plants were not sufficiently significant to be included.

Personnel error either directly or indirectly caused about 20% of the SI actuation. This number is roughly similar to the percentage of overall LER involving human error. Therefore, it is not believed that personnel error is a particularly significant contributor to spurious or inadvertent SI actuations. However, that does not mean that better operator training and better procedures will not improve the situation.

About a third of the SI initiations occurred when some test or maintenance was ongoing not only on the safety injection actuation system but also on other equipment located nearby. This number highlights the need to improve the skill and training of technicians and maintenance personnel as well as the quality of the procedure related to these activities.

VIII SIMULTANEOUS FAILURE UPON SI INITIATION

This review of SI actuation was also an opportunity to look at the safety injection system behavior upon demand. The selected LERs in the ORNL file, as well as the reports submitted to the B&O task force were screened for concurrent failure in the safety injection system or their supporting system (component cooling or electrical power) upon demand. The review covered about

140 SI actuations where such failure could have been reported. Seventeen instances of additional failures independent from the cause of the SI initiation were identified. They are listed in Table 6. Five of these seventeen events could have resulted in the failure of the SIS to perform its safety function automatically (Beaver Valley, July 28, 1978; Indian Point 2, June 24, 1974; Trojan, October 28, 1976; Zion 1, August 15, 1974; Zion 2, October 22, 1974). Fortunately, on each of these five occurrences operator actions have resulted in at least partial restoration of the safety function; and, all of these five SI were either spurious or inadvertent.

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From these data it could be inferred that the probability of having an additional failure that reduces the capability of a safety system upon demand is on the order of 10^{-1} per demand as a minimum. Therefore, this would support the requirement for assuming a single failure in ESFs in FSAR studies.

In addition, it appears that the total disabling of the automatic operation of a redundant safety system on demand is not an incredible event. This is a confirmation of the need to incorporate as a first step in each emergency procedure some instructions to the operator to verify the proper operation of every automatic action.

IX CONCLUSIONS

Too many unnecessary challenges of the safety injection system can potentially lead to two adverse effects. An increase in the usage factor of the SI nozzles that could become unacceptable before the normal end of plant life; and an operator becoming acclimated to believe every SI initiation is unnecessary and, accordingly, terminating the SI before a comprehensive evaluation of the event has been performed.

The review of operating experience with SI actuation performed in this study shows that these two areas of concern are not applicable to CE plants up to the present time. The usage factor on SI nozzles could have been a problem of concern on B&W units because of a tendency of the operators to actuate the SI manually upon almost every reactor trip in order to recover the pressurizer level. This action has been demonstrated as unnecessary, and B&W operators have been instructed not to pursue this habit. Therefore, it is believed that this problem has been resolved.

Some Westinghouse reactors had experienced more than three SI per reactor year. There might be a problem with SI nozzles' usage factor before the end of life of these units should there be no improvement. In addition, W units have a high rate of automatic, unnecessary SI (less than 15% are needed SI). Therefore, we are concerned with the operator tendency to consider every SI as spurious or inadvertent. Plants of more recent vintage seem to have a greater sensitivity to unnecessary SI than the older ones. The cause of the high rate of unneeded SI can be traced at least partially to the complexity of the

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steamline break detection system that incl es several parameters on the secondary side that would initiate the SI. Such modification as proposed at Beaver Valley to reduce the number of the secondary side initiating parameters could significantly improve the reliabil of the SI initiation system.

About a third of SI actuations occurred d ing test or maintenance operation. Better performance of operating activitie could improve the situation with this regard. This concern has been addressec n the TMI Action Plan item I.C.6.

In case of SI initiation, the probabili of having an additional failure independent of the cause of the SI, th duces the capability of the safety injection system, is of the order of 10 per demand. The experience also shows that the total disabling of automatic operation of the safety injection system due to hardware failure is not an event of very low probability.

X RECOMMENDATIONS

1. We recommend that for those units that experience three or more SI actuations (automatic or manual, spurious or needed) in a single calendar year, the licensees be required to report to the NRC the calculation of the actual usage factor on the SI nozzle in order to allow the NRC staff to closely follow the evolution of these usage factors.

2. We recommend the development of a diagnostic procedure based on a definite set of criteria to help the operators to recognize whether an SI is spurious or not. This procedure should be implemented on every unit.

3. If the NRC staff approves the license amendment submitted by the Beaver Valley licensee for a new steamline break protection system, we would recommend that the same modification be applied to other W units that had experienced the greatest number of SI. This modification has the potential for significantly decreasing the number of unnecessary SI.

4. The implementation of the recommendation of TMI Action Plan item I.C.6 should emphasize the need for proper attention to maintenance and testing of the safety injection actuation system as well as of nearby equipment.

5. Emergency procedures should be reviewed to ensure they include, as a first step, instructions for the operator to verify the proper operation of all automatic sequences of action that the SI initiation should initiate. This recommendation could be implemented under TMI Action Plan item I.C.1.

Table 1

SI Categorization — Westinghouse Units

Unit Name	Total Number	Average Frequency	Transient or Accident	Spurious	Inadvertent	Unknown	Personnel Error	Test or Maintenance
Beaver Valley	15	2.9	2	10	2	1	5	3
D.C. Cook 1	14	2.5	0	8	1	5	3	3
D.C. Cook 2	3	1.1	0	1	0	2	0	0
J.M. Farley 1	6	1.8	0	4	1	1	4	3
Ginna	1	0.1	1	0	0	0	0	0
Haddam Neck	6	0.4	0	4	0	2	1	1
H.B. Robinson	3	0.3	2	1	0	0	0	0
Indian Point 2	9	1.2	0	3	4	2	0	2
Indian Point 3	1	0.2	0	0	0	1	0	0
Kewaunee	1	0.1	0	1	0	0	0	0
North Anna	5	1.9	2	2	1	0	0	2
Point Beach 1	1	0.1	1	0	0	0	0	0
Point Beach 2	0	0	0	0	0	0	0	0
Prairie Island 1	8	1.1	1	6	1	0	2	2
Prairie Island 2	1	0.2	0	1	0	0	0	1

Table I (continued)

SI Categorization — Westinghouse Units

Unit Name	Total Number	Average Frequency	Transient or Accident	Spurious	Inadvertent	Unknown	Personnel Error	Test or Maintenance
Salem 1	12	3	4	5	3	0	4	6
San Onofre 1	3	0.2	2	0	0	1	1	0
Surry 1	6	0.7	2	0	0	4	0	0
Surry 2	10	1.2	1	2	0	7	0	0
Trojan	6	1	1	0	3	2	4	2
Turkey Point 3	1	0.1	0	1	0	0	0	0
Turkey Point 4	1	0.1	0	4	0	0	0	1
Yankee Rowe	4	0.2	0	0	0	4	0	0
Zion 1	24	3.2	1	8	11	4	7	8
Zion 2	24	3.4	2	11	9	2	7	13
Total	165	0.84	22	69	36	38	39	47
Percentage	100%		13%	42%	22%	23%	23%	28%

Table 1 (Continued)

	SP Categorization		Combustion Engr Units					
Unit Name	Total Number	Average Frequency	Transient or Accident	Spurious	Inadvertent	Unknown	Personnel Error	Test or Maintenance
Arkansas 2	3	1.5	1	0	0	2	0	1
Calvert Cliffs 1	5	0.8	1	4	0	0	3	4
Calvert Cliffs 2	0	0	0	0	0	0	0	0
Fort Calhoun	1	0.1	1	0	0	0	0	0
Maine Yankee	2	0.4	0	2	0	0	1	2
Millstone 2	1	0.2	0	0	0	1	0	0
St. Lucie	7	1.5	4	0	0	3	0	0
Palisades	5	0.5	5	0	0	0	0	0
Total	24	0.5	12	6	0	6	4	7
Percentage	100%		50%	25%		25%	16%	29%

Table 1 (Continued)

SI Categorization

Babcock and Wilcox Units

Unit Name	Total Number	Average Frequency	Transient or Accident	Spurious	Inadvertent	Unknown
Arkansas 1	14	2.15	3	0	11	0
Crystal River 3	20	5	2	2	16	0
Oconee 1	16	2	1	0	15	0
Oconee 2	10	1.4	2	0	8	0
Oconee 3	9	1.4	3	1	5	0
Rancho Seco	26	4.2	3	0	18	5
Total	95	2.7	14	3	73	5
Percentage	100%		15%	31%	76.7%	5.2%

(c) With respect to the telephone notifications made pursuant to

Table 2

Westinghouse Units - ECCS Initiating Parameters

	HCP psi	LRP* psi	SΔP psi	HSF** + L Tavg**	HSF** + LSP psi
Beaver Valley	1.5	1765	100	543°F	500
D.C. Cook 1	1.1	1815	100	541°F	600
D.C. Cook 2	1.1	1900	100	N/A	600
Farley 1	5.4	1850	100	NA	585
Ginna	6	1715	NA	NA	500
Haddam Neck	5	1700	NA	NA	NA
H.B. Robinson	4	1715	100	543°F	614
Indian Point 2&3	2	1700	150	540°F	600
Kewaunee	4	1815	NA	NA	NA
North Anna 1	2.3	1765	100	543°F	600
Point Beach 1&2	5	1735	NA	NA	530
Prairie Island 1&2	4	1815	100	NA	500***
Salem 1	4.7	1765	100	543°F	500
San Onofre 1	NA	1865	NA	NA	NA
Surry 1&2	3	1715	100	543°F	525
Trojan	5	1765	100	553°F	600
Turkey Point 3&4	4	1715	100	543°F	600
Yankee Rowe	5	NA	NA	NA	NA
Zion 1&2	4.5	1815	100	540°F	600

Acronyms: LRP =low reactor pressure
HCP =high containment pressure
SΔP = high pressure difference between steam line
LSP=low steam pressure
HSF=high steam flow
L Tavg=low low primary average temperature

* Before TMI most W designs provided for coincidence between low reactor pressure and low pressurizer level. This coincidence has been removed now.
** the high steam flow is a function of load
*** Low steam pressure only

Table 3

Correlation of SI Frequency and Number of SI Initiating Parameters

Plant	Number of SI Parameters	SI Frequency	Average SI Frequency
Beaver Valley 1	5	3	
D.C. Cook 1	5	2.5	
H.B. Robinson	5	0.3	
Indian Point 2&3	5	1.2/0.2	
North Anna 1	5	1.9	1.56
Salem 1	5	3	
Surry 1&2	5	0.7/1.2	
Trojan	5	1	
Zion 1&2	5	3.2/3.6	
Turkey Point 3&4	5	0.1/0.1	
D.C. Cook 2	4	1.1	
Farley	4	1.8	1.05
Prairie Island 1&2	4	1.1/0.2	
Ginna	3	0.1	0.01
Point Beach 1&2	3	0.1/0	
Haddam Neck	2	0.4	0.25
Kewaunee	2	0.1	
San Onofre	1	0.2	0.2
Yankee Rowe	1	0.2	

Table 4

Correlation between SI frequency and the age of the unit

Unit	Year of 1st Criticality	SI Frequency perreactor year
Yankee Rowe	1960	0.2
Haddam Neck	1967	0.4
San Onofre	1967	0.2
Ginna	1969	0.1
Point Beach	1970	0.1
H.B. Robinson	1970	0.3
Turkey Point 3	1972	0.1
Point Beach 2	1972	0
Surry 1	1972	0.7
Indian Point 2	1973	1.2
Surry 2	1973	1.2
Turkey Point 4	1973	0.1
Prairie Island 1	1973	1.1
Zion 1	1973	3.2
Zion 2	1973	3.4
Kewaunee	1974	0.1
Prairie Island 2	1974	0.2
D.C. Cook 1	1975	2.5
Trojan	1975	1
Salem	1976	3
Indian Point 3	1976	0.2
Beaver Valley	1976	2.9
Farley 1	1977	1.8
North Anna 1	1978	1.9
D.C. Cook 2	1978	1.1

Table 5

SI Initiating Parameters Versus SI Categorization

	Transients or Accident			Spurious			Inadvertent			Unknown			Total		
	No.	Row %	Col. %	No.	Row %	Col. %	No.	Row %	Col. %	No.	Row %	Col. %	No.	Row %	Col. %
LRP	10	45.5%	45.5%	9	40.9%	13.2%	0	0%	0%	3	13.6%	7.9%	22	100%	13.4%
SΔP	1	2.5%	4.5%	7	17.1%	10.3%	29%	70.7%	80.6%	4	9.7%	10.5%	41	100%	25%
HSF + L Tavg or HSF + LSP	[illegible]	23.5%	[illegible]	13	53.0%	26.5%	5	14.7%	13.9%	3	8.0%	7.9%	34	100%	20.7%
LSP	0	0%	0%	5	83.3%	7.4%	0	0%	0%	1	16.7%	2.6%	6	100%	3.7%
SIAS Logic	0	0%	0%	19	100%	27.9%	0	0%	0%	0	0%	0%	19	100%	11.6%
Manual	2	33.3%	9.1%	2	33.3%	2.9%	2	33.3%	5.5%	0	0%	0%	6	100%	3.7%
Unknown	1	2.8%	4.5%	8	22.2%	11.8%	0	0%	0%	27	75%	71.1%	36	100%	21.9%
Total	22	13.4%	100%	68	41.5%	100%	36	22.0%	100%	38	23.1%	100%	164	100%	100%

Table 6

Additional Failure Upon SI Demand

Beaver Valley 1	7-28-78	2 Diesel Generator field failed to automatically flash
D.C. Cook 1	9-30-76*	No status lights were received and no reactor trip occurred
Calvert Cliffs 1	11-11-74*	Inadvertent spray in containment through a leaking valve
Farley 1	6-06-78	1 Charging pump and 1RHR pump did not start
Ginna	10-23-73*	Premature suction switch from BAT to RWST
Indian Point 2	4-19-74*	1 DG start but did not develop the required voltage
Indian Point 2	6-24-74	4 valves on the Boron Injection Tank outlet closed
Indian Point 3	01-12-77	1 HPI pump failed to start
H.B. Robinson 2	11-30-72*	1 Valve did not open in the safety injection system
San Onofre	6-31-74*	Water hammer in safety injection system damaged valve and hanger
Surry 2	11-23-73*	1 HPI pump failed to start
Trojan	10-28-76	2 HPI pump suction valves failed to open on demand
Trojan	3-02-77	1 [illegible] pump failed to start
Zion 1	8-15-74	Design error caused no SI initiation upon SAP signal
Zion 2	8-29-74	1 Safety injection system valve did not actuate
Zion 2	10-22-74	A logic did not actuate and BIT discharge valve in train B did not open
Zion 2	7-19-76	1 Diesel generator failure

#18

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DEC 0 8 1981

MEMORANDUM FOR: Carlyle Michelson, Director
Office of Analysis and Evaluation of Operation Data

FROM: Harold Denton, Director
Office of Nuclear Reactor Regulation

SUBJECT: COMBINATION PRIMARY/SECONDARY SYSTEM LOCA

Reference:

1. Memorandum, Dircks to Commissioners, "Resolution of Issue Concerning Steamline Break with Small LOCA," dated December 23, 1980.

2. Memorandum, Sheron to Speis, "Combined Blowdown Analysis," dated September 28, 1981

The purpose of this memorandum is to inform you of the results of my staff's evaluation of combined primary/secondary system LOCAs. This evaluation was performed as part of the agreed upon resolution plan for this issue as documented in reference (1) and (2).

As you recall, the objective of this evaluation was to determine if (a) nuclear plants could accomodate the combination primary/secondary system LOCA and (b) the operators have adequate emergency procedures for coping with combination LOCAs. The results of this evaluation would provide the technical bases upon which a decision could be made to either include or eliminate the AEOD combination LOCA concern as a USI prior to the USI report to Congress to be issued in early 1982.

The reference (1) memorandum informed the Commission of the resolution plan for the AEOD concern on combined primary/secondary system LOCAs. The reference (2) memorandum documented the details of the evaluation that would be performed by NRR and RES and were agreed to with you.

Our evaluation was divided into two phases; phase 1 addressed plants with inverted U-tube steam generators (W and CE); phase 2, which is still ongoing, addresses plants with once-through steam generators (B&W).

This memorandum transmits for your information the results of the first phase of our evaluation, which is enclosed.

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XA

RD-8-3
ECCS

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Our conclusion, based on the RES analyses of the accident scenarios documented in reference (2), is that plants with Westinghouse-designed NSSSs are adequately protected against combined primary/secondary system LOCAs except for cases when the steamline break outside of containment cannot be isolated. We believe that adequate protection for these cases can be achieved by appropriate upgrading of emergency guidelines and procedures. We intend to accomplish this as part of our review and approval of emergency operator guidelines being performed under TMI Action Plan Item I.C.1. We expect to complete the above reviews by the end of the fiscal year. We believe the probability of the specific scenarios which may not be appropriately covered in existing plant procedures is sufficiently low that resolution on a more expeditious schedule is not warranted.

The Reliability and Risk Assessment Branch (RRAB) in NRR is confirming this conclusion. If the probability is determined to be unacceptably high more immediate action will be taken.

Although we have not completed the second phase of our evaluation, our preliminary conclusion is that adequate protection exists or will be provided to protect against combination LOCAs that they should not be designated as a USI.

We will confirm or modify this conclusion following completion of the second phase of the evaluation. The results of this second phase will be forwarded to you shortly.

Original Signed By
H. R. Denton

Harold R. Denton, Director
Office of Nuclear Reactor Regulation

Enclosure:
As stated

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DATE	11/ /81	11/ /81	11/ /81	11/ /81	11/ /81		

EVALUATION OF THE ISSUE CONCERNING
STEAMLINE BREAK WITH SMALL LOCA,
WESTINGHOUSE NSSS PLANTS

1. BACKGROUND

During the last half of 1980 the NRC Office for Analysis and Evaluation of Operational Data (AEOD) issued two memos (Ref. 1 and 2) in which they raised a potential safety issue involving combined primary and secondary system LOCAs. The issue was discussed at the Commission meetings on October 16, 1980 and on November 10, 1980. As a result of the Commission meetings, NRR committed to evaluate the concern as part of their ongoing review of emergency operator guidelines. This report presents the results of that review.

The AEOD concern postulates an accident resulting in coincident steamline break, steam generator tube rupture, and small LOCA. In Ref. 2 AEOD has described various scenarios which are postulated to lead to such a situation. Most of them start from a failure of the steam generator level control, causing overfilling and overcooling of one steam generator. The basic AEOD concern (in addition to assuring the consequences of such a postulated event are acceptable) is that plant operators are not provided sufficient guidance to respond properly to such an event.

In response to the AEOD concern, the NRC Office of Nuclear Reactor Regulation has suggested (Ref. 3) that the concerns could best be addressed as two separate issues. The first involves transients that could lead to gross overfilling of the steam generators. The second involves postulated accidents in which a PWR steam line rupture is followed by a small break in the primary system. NRR has further agreed to include the first issue as a part of the Unresolved Safety Issue Program Task A-47, Safety Implications of Control Systems. The second issue will be addressed in this memorandum.

This memorandum presents an evaluation for plants with Westinghouse designed NSSS. The evaluation is based on the analyses performed by the NRC Office of Nuclear

Regulatory Research at Los Alamos National Laboratory (Ref. 4) and on the emergency guidelines submitted by the Westinghouse Owners Group under the topic I.C.1 of TMI Action Plan.

A corresponding evaluation for plants with Babcock & Wilcox designed NSSS will be presented after the related analyses have been reported by Los Alamos National Laboratory. All calculations needed for the evaluation have been completed during summer 1981 and the report will be issued in November 1981.

No specific calculations of these specific scenarios are considered necessary for C-E designed NSSS plants but the evaluation, to be presented in a later stage, will be based on the analyses for Westinghouse plants and on the emergency guidelines submitted by the C-E Owners Group.

During the evaluation it became obvious that the plant response and the operator actions may vary considerably depending on the location of the steam line break. Thus, the evaluation has been accordingly divided into three parts. The other factors, like break sizes or the primary break location, are of less importance to the general course of the accident.

2.0 CALCULATED PLANT RESPONSE

Calculations of a combined primary and secondary system leakage have been performed with the TRAC-PD2 code for the Zion plant (Ref. 4). The specific initiating combinations of events were:

Case 1

- o Double-ended main steamline break
- o Double-ended rupture of one steam generator tube in the steam leaking SG
- o A 2-inch diameter break in the primary system hot leg

Case 2

- o Double-ended main steamline break
- o Double-ended rupture of one steam generator tube in the steam leaking SG
- o A 2-inch diameter break in the primary system cold leg

Case 3

- o Double-ended main steamline break
- o Double-ended rupture of one steam generator tube in the steam leaking SG

Case 4

- o Double-ended main steamline break
- o Double-ended rupture of five steam generator tubes in the steam leaking SG

Double-ended main steamline break was assumed because it causes the most severe initial transient and also has the greatest potential to obscure the coincident tube rupture by isolating the SG rapidly from the secondary side radiation monitors. As shown later, the operator actions would be the same for any steamline break which depressurizes one SG to a clearly lower pressure than the others.

The initial operating condition in each case was normal full power operation. The calculations were realistic best-estimate type calculations and the automatic protection systems were assumed to operate as designed. The only operator action assumed was switching the primary coolant pumps off concurrently with the start of the safety injection system in accordance with present plant procedures.

All four transients were qualitatively similar, as shown in figures 1a, 2a, 3a and 4a. The case no. 2 is not presented separately because its results were so close to the case no. 1. In each case the main steamline break caused a rapid blowdown of the secondary side of the affected steam generator. During this blowdown, there was overcooling and partial depressurization of the primary coolant system, with consequent activation of the safety injection system on low pressure. Within several minutes, the safety injection flow became sufficient to compensate for the losses from the primary system breaks, and the system was essentially stabilized. The primary pressure never dropped enough to activate the accumulators or the low-pressure injection system. The core always remained covered with liquid, and the primary system remained subcooled except for a nearly stagnant region in the vessel upper head.

The calculations were terminated 15 minutes after the initiating events. At the end of the calculations, the plant parameters were stable except for the rising pressurizer level in the case no. 3 and the decreasing reactor coolant temperature in the case no. 4.

There appears to be nothing in the response of the primary or secondary systems which will indicate uniquely to the operator whether there is a primary piping break or a steam generator tube rupture or both in addition to a main steamline break.

The postulated accidents used in the operator training and as a basis for the present emergency guidelines are those analyzed in the FSAR. Thus, it can be expected that the operator tries initially to diagnose the combined accident as one of the single events he has learned to cope with.

To compare the combined accidents with those expected by the operator, we present in figures 1b, 2b, 3b, and 4b the plant response to the following events:

- o A double-ended rupture of one steam generator tube
- o A two-inch diameter break in the primary system cold leg
- o A double-ended main steamline break.

From these three events, only the steam generator tube rupture can be quantitatively compared to the combined accidents because it was analyzed with the same best-estimate TRAC-PD2 model (ref. 5). The two other events have been calculated by Westinghouse using their conservative licensing models. The cold leg break results are taken from the reference 6 and the steamline break results from the reference 7. It should be further noticed that all other events start from full power but the initial condition for the steamline break is hot shutdown. On the other hand, some power production in the core, largely compensating the smaller initial stored energy, is calculated during the first minute of the steamline break accident.

In conclusion, from the figures attached to this memorandum it can be seen that the primary and secondary system parameters used by the operator for the accident diagnosis behave in the combined events qualitatively like a steamline break. The primary pressure and the pressurizer level may change qualitatively in the same way during any of the combined or single events but the primary temperature and the secondary pressure during cold leg break or steam generator tube rupture are clearly distinctive from the steamline break and the combined accidents.

3.0 EMERGENCY OPERATING GUIDELINES

The expected operator actions have been estimated on the basis of the Emergency Response Guidelines, submitted by the Westinghouse owners group. This overall procedural set is composed of two parts, Optimal Recovery Guidelines, and Critical Safety Function Restoration Guidelines and Status Trees. The first part is basically similar to the emergency operating procedures that exist currently at the operating plants. The second part, still under development, is not needed during the accident in question because no critical safety function is expected to be challenged (that is, the core will remain subcritical, covered, and cooled throughout all of the combined events analyzed here, and no excessive RCS pressure, loss of heat sink, or risk for the containment integrity is expected).

The first instruction the operator uses for his immediate actions and diagnostics after each reactor trip or start of safety injection is designated E-0. If the safety injection is not initiated by a spurious signal the operator will later on use one or more of the following instructions:

- o E-1 Loss of Reactor Coolant
- o E-2 Loss of Secondary Coolant
- o E-3 Steam Generator Tube Rupture

All steps described in instruction E-0 to verify plant status and to correct the possible deficiencies in automatic protective functions are applicable also in the case of a steam line break, coincident with steam generator tube rupture and small LOCA. Specifically the operator is told to stop primary coolant pumps (as assumed in the analysis), to isolate the main feedwater system if the automatic system has failed to do so, and to make sure that the pressurizer relief path is closed, either by PORV or the block valve.

To diagnose the event, the operator is advised to first check for the secondary side integrity by looking at the steam generator (SG) pressures. Low pressure in any SG tells him to go to E-2, Loss of Secondary Coolant.

If not directed to E-2, the operator will next check the containment indications: pressure, radiation, and sump level. Any changes in these parameters guide him to E-1, Loss of Reactor Coolant.

If still staying in E-0 the operator checks finally the radiation signals from the condenser air ejector and the SG blowdown line. High readings guide him to E-3, Steam Generator Tube Rupture.

If the operator has passed all the exits from E-0 but the SI is still on and the SI termination criteria are not met he will continue in the instruction E-2.

4.0 EXPECTED OPERATOR ACTIONS

4.1 Steamline Break Inside the Containment

The break location is indicated as break no. 1 in figure 5. As far as the operator does not take any actions except the manual trip of the reactor coolant pumps the analysis results presented in section 2.0 are valid.

It is obvious that during the diagnosis in accordance with the instruction E-0 the operator will notice the decreased pressure in one steam generator and go to the instruction E-2, Loss of Secondary Coolant. It is reasonable to expect that the noise from blowdown alone would hint to the operator that a steamline was blowing down.

The main task to mitigate the loss of secondary coolant, as advised in the instruction E-2, is to stop auxiliary feedwater to the faulted SG and to regulate auxiliary feedwater to intact SGs to maintain the normal level. If the transient goes on as analyzed there are no explicit exits from E-2 to other instuctions and it can be expected that the operator is going to follow the E-2 instuctions for awhile.

As long as the temperature is above 350°F, the safety injection (SI) is continued using the same termination criteria as in the case of a primary system LOCA. The margin to SI termination criteria stays large in all of the calculated cases and SI would continue stabilizing the primary pressure to a value where SI compensates for the primary coolant losses from the breaks. Sooner or later it is expected that the operator would question the continued SI flow and suspect the existence of either a SG tube rupture or a small LOCA. Because the operator has no means to single our one of the two choices he may go to either E-1, Loss of Reactor Coolant, or to E-3, Steam Generator Tube Rupture. While staying in E-2, the operator is reminded to monitor the refueling water storage tank (RWST) level and to realign the safety injection pumps to the cold leg recirculation mode if the RWST low-low level alarm is reached. If the operator goes from E-2 to E-1 he will be in an instruction that is applicable until the final plant recovery and cooldown. If the operator goes first from E-2 to E-3 he is advised to go further to E-1 as soon as he sees containment indications deviating from the normal pre-event range. Thus he will end up with the appropriate instruction.

The analysis results indicate that in each case the core average temperature is above 460°F when the calculation is terminated at 15 minutes into the transient. Thus the 350°F temperature limit is probably not reached before the operator has gone to E-1. Should the temperature in the hot leg decrease below 350°F before the operator has recognized the primary leakage he would terminate SI to avoid primary system pressurized thermal shock. After SI termination the operator is told to carefully monitor the RCS pressure, pressurizer level, and reactor coolant subcooling. These will inevitably drop in such a way that the operator is told to restart SI and to rediagnose the event. At this stage, he should notice the direct leakage from the primary system and go to E-1 for a proper plant recovery and cooldown.

In conclusion, if the steamline break is inside the reactor containment the consequences of the combined accident are not expected to be beyond the plant design basis and the operator is able to recover and cooldown the plant using the existing emergency operating procedures.

4.2 Steamline Break Between the Containment Penetration and the Main Steam Isolation Valve

The break location is indicated as break no. 2 in figure 5. The short term response of the primary and secondary circuits is essentially similar for all double-ended steamline breaks upstream from the main steam isolation valves. Thus the TRAC-PD2 calculations described in section 2.0 are also valid for this case.

The differences between breaks inside vs. outside the containment are in the containment response, radiological consequences, and operator response. For the breaks outside containment it is also possible to diagnose a coincident small LOCA and steam generator tube rupture. The small LOCA is indicated by the containment parameters deviating from their normal pre-event values. The tube rupture is evidenced by the radioactive steam leaking from the broken steam line. Without a tube rupture the faulted SG would rapidly boil dry and any steam leakage would stop. The steam leak can not be detected from the control room indications but local visual observations and radiation monitoring are needed.

As in the previous section the operator would first use the instruction E-0 and then go to E-2, Loss of Secondary Coolant, guided by the low pressure in one SG. He would probably also get a direct audible indication of the leaking steam.

Having verified the broken steamline and having the related steam generator isolated the operator would soon notice the containment indications and the continuing SI flow. This would guide him to the instruction E-1, Loss of Reactor Coolant. An entry to the instruction E-3, Steam Generator Tube Rupture is not expected because the indications of SG tube rupture would not be available in the control room for the following reasons:

1. the detectors for measuring the increased radiation in the secondary system are beyond the isolation valves, and
2. the faulted steam generator is boiled dry even in the case of double-ended ruptures of five SG tubes and the leak, flashing to steam on the secondary side, does not give indication of unexpected water flow into the SG.

If the operator just follows his instructions and does not get visual observations or radiation monitor readings from the broken steam line it is possible that the SG tube rupture stays unnoticed and the situation is treated in the long term like a small break LOCA. It is thus possible that the primary pressure is kept high and an uncontrolled leakage of primary coolant directly to the atmosphere continues for hours. The leakage would cause radiological consequences not analyzed in FSAR and a loss of water inventory from ECC recirculation. As an example, we have estimated that for case no. 1 of the TRAC-PD2 calculations, the time for leaking a mass equivalent to the RWST contents would be about one day. In cases no. 3 and no. 4 the time would be smaller, possibly not more than five hours in case no. 4.

Even if the operator would notice the SG tube rupture he would not have an instruction to cope with the accident. The instruction E-3 is based on the assumption that the secondary side of the faulted SG is able to retain its full design pressure and the primary to secondary leakage is stopped after the primary pressure has decreased below the secondary safety valve setpoint. However, the open leak path from the reactor coolant system to the atmosphere would call for fast cooling of the primary system down to cold shutdown conditions.

In conclusion, if the steamline break is between the containment penetration and the main steam isolation valve the radiological consequences could be more severe than in any accident currently analyzed in FSAR. There would also be a continuous loss of the water inventory available for reactor cooling. Without proper operator actions to decrease the primary coolant pressure, the coolant loss would jeopardize ECC recirculation within a few hours. The instructions currently available to the operator are not applicable to cope with the accident.

4.3 Steamline Break Downstream of the Main Steam Isolation Valve

The break location is indicated as break no. 3 in figure 5. The TRAC-PD2 calculations described in Section 2.0 are valid for this case only until the isolation of the main steamlines. In a typical Westinghouse plant the isolation valves are completely closed within 10 seconds from the event initiation.

The reactor coolant temperature does not decrease below 500°F during the initial transient and the following stabilization. The secondary system pressures does not decrease below 500 psi, and after the main steam isolation valve closure it increases rapidly to the SG relief valve setpoint.

If the direct leak from the reactor coolant system break to the containment is large enough to remove all decay heat (typically about 2-inch diameter break) the primary pressure will decrease below the SG relief valve setpoint and there will be no continued primary to secondary leak. It is probable that the operator does not notice the SG tube rupture until a long time after the initiating event. In any case, the containment indications would guide him to go to the instruction E-1, Loss of Reactor Coolant. That instruction would provide the necessary advice for a proper plant recovery and cooldown, except for the measures potentially needed to avoid excessive reactor coolant boron dilution. The dilution would continue until the operator discovers the secondary to primary leakage from unexpected behavior of level control in one SG and takes the actions to equalize the pressure in that SG and the primary circuit.

If the direct leak from the reactor coolant system break to the containment is small, the secondary pressure stabilizes to the SG relief valve setpoint and the primary pressure stays higher. Thus, there will be a continued leak from primary to secondary and further to the atmosphere through the relief valves. The stable secondary side in combination with containment indications guide the operator to instruction E-1, Loss of Reactor Coolant. This instruction tells him to reduce the SG pressure 200 psi below the lowest steam system safety valve setpoint by dumping steam to the atmosphere. Thus, the primary-to-secondary leak will continue until the operator observes unexpected behavior of level control in one SG. Specifically, E-1 reminds him to look at the SG levels and to go to E-3 if level in any SG increases. Once the tube rupture has been diagnosed, the primary system is depressurized to the pressure of the faulted SG and the decay heat removal and the plant cooling is performed using the intact SGs, as advised in E-3. The faulted SG is kept at the same pressure as the primary system and it is cooled down independently by feed and bleed method. The offsite doses are related to the total amount of reactor coolant leaked to the SG before the pressure equalization. To put the time scale in perspective, it may be mentioned that a typical SG tube rupture analysis in the FSAR assumes operator actions to stop the leakage to the faulted SG at 30 minutes after the rupture. In the combination LOCA, the primary pressure gets smaller than in the single tube rupture event and thus the operator would have more time for diagnosis and for measures to terminate the leakage.

In conclusion, if the steamline break is located downstream from the main steamline isolation valves the initial transient in the primary and secondary circuits is short and the plant is stabilized automatically. During the recovery stage there is a potential of a reactor coolant boron dilution (large primary system LOCA) or radiological consequences exceeding those analyzed in FSAR (smaller primary system LOCA). After the operator discovers the SG tube rupture from the unexpected level variation in one SG, he can cooldown the plant using instruction E-3, Steam Generator Tube Rupture. At the same time, he has to operate the ECCS and the decay heat removal system, as told in the instruction E-1, Loss of Reactor Coolant.

5.0 SUMMARY

The calculations performed indicate that in all of the analyzed cases the primary coolant shrinkage, caused by overcooling, and the simultaneous loss of coolant can be compensated by the high pressure ECCS. The core remains covered with liquid, and the primary coolant remains subcooled, except in the vessel upper head.

If the steamline break is inside the containment, the offsite releases are not higher than in the events currently analyzed in the FSAR and the operator is provided sufficient guidance for a safe cooldown. This is most probably the case also for the steamline break downstream of the main steam isolation valves.

If the steamline break is outside the containment and cannot be isolated, the radiological consequences could be more severe than in any accident currently analyzed in the FSAR. To decrease the risk of elevated offsite releases, an early diagnosis of the tube rupture has to be assured. This can be done by upgrading the operator instructions. The appropriate mitigating actions are already found in the existing instructions; but the operators have to be specifically trained for combined LOCAs to make sure they are able to use their instructions in such a situation.

REFERENCES

1. Memo from C. Michelson, Director , AEOD, to Chairman Ahearne Dated August 4, 1980.
2. Memo from C. Michelson, Director AEOD, to H. Denton, Director, NRC, dated November 7, 1980.
3. Memo from H. Denton, Director, NRR, to Commissioners, NRC dated November 7, 1980.
4. Memo from S. Fabic, RES, to Paul Check, NRR, dated May 6, 1981.
5. Draft report by Dean Dobranich: Steam Generator Tube Rupture Analysis for Zion-1, Los Alamos National Laboratory, September 1981.
6. Westinghouse Topical Report WCAP-9600, Report on Small Break Accidents for Westinghouse NSSS Systems, June 1979.
7. Zion, FSAR.

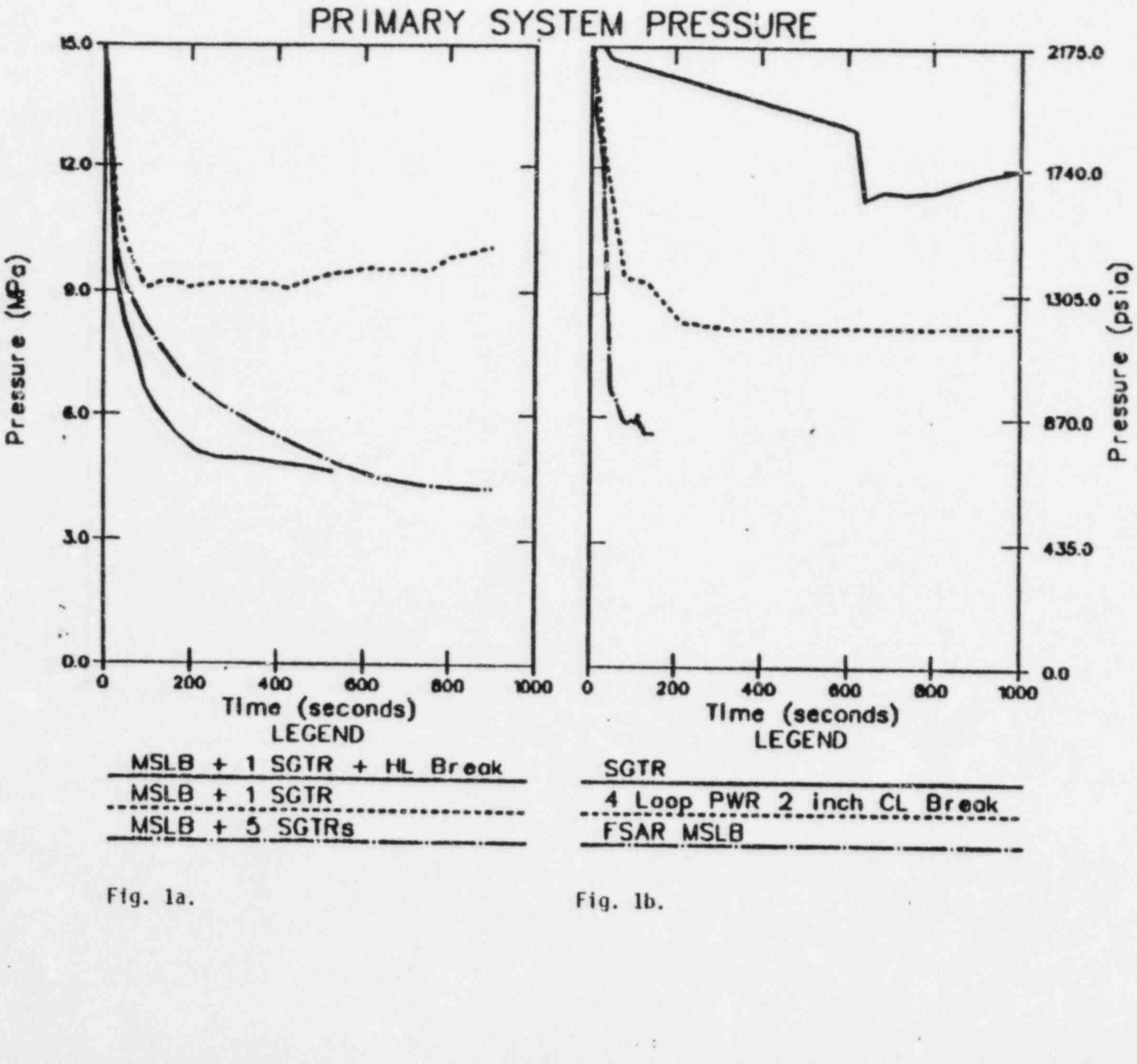

PRIMARY SYSTEM PRESSURE
Pressure (MPa)
15.0
12.0
9.0
6.0
3.0
0.0
0
200
400
600
800
1000
Time (seconds)
LEGEND
MSLB + 1 SGTR + HL Break
MSLB + 1 SGTR
MSLB + 5 SGTRs
Pressure (psia)
2175.0
1740.0
1305.0
870.0
435.0
0.0
Time (seconds)
LEGEND
SGTR
4 Loop PWR 2 inch CL Break
FSAR MSLB

Fig. 1a.

Fig. 1b.

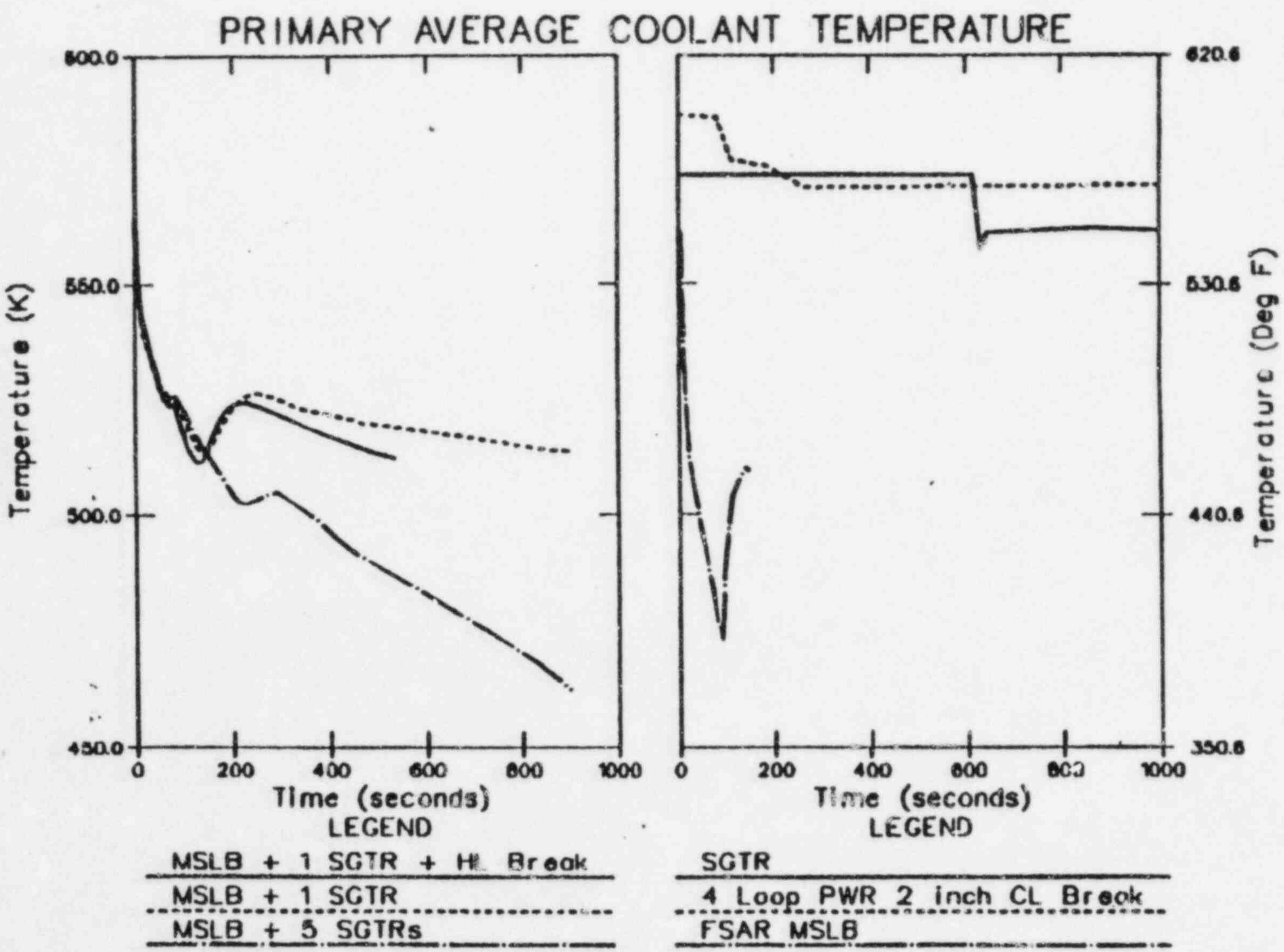
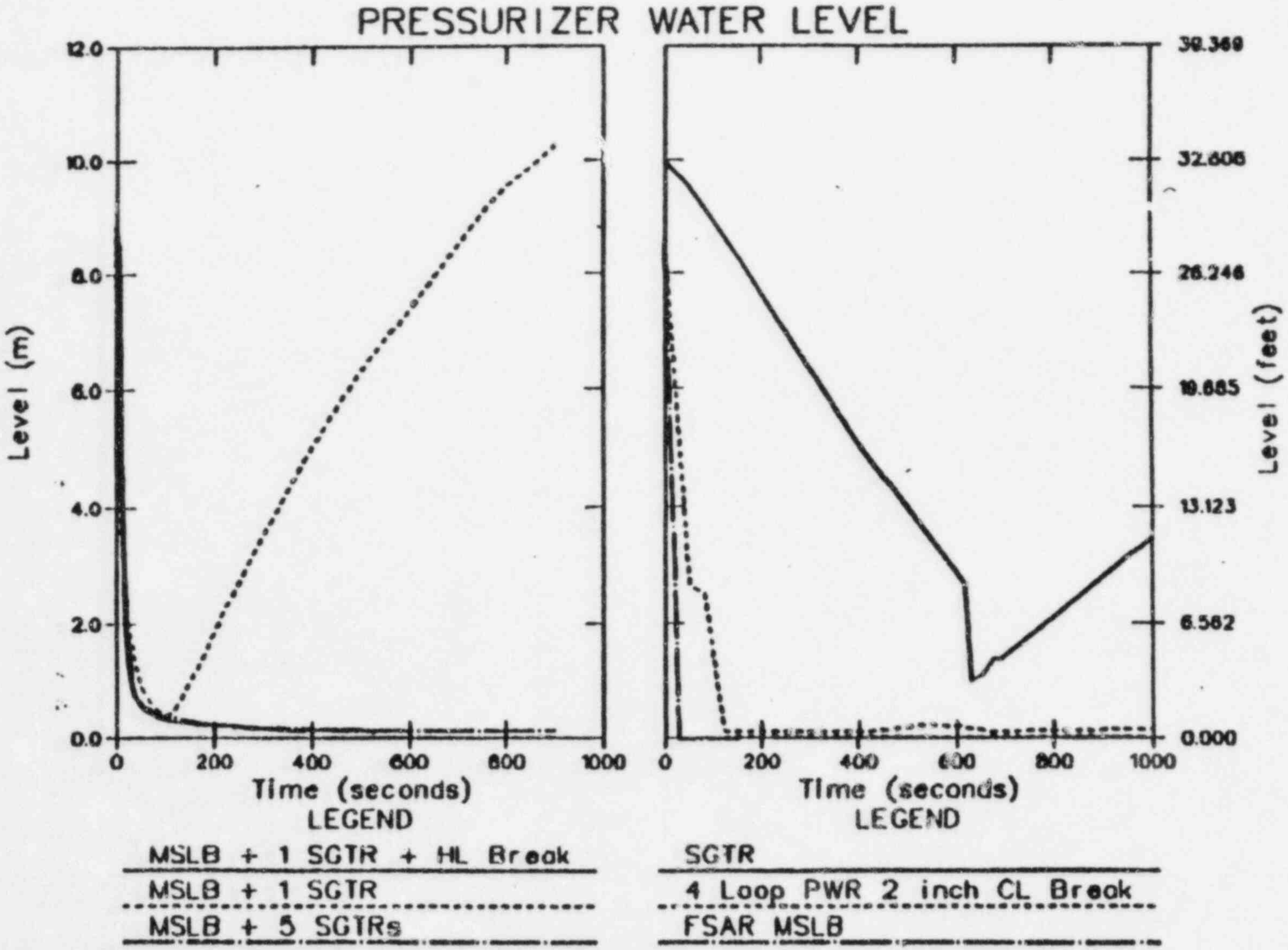

PRIMARY AVERAGE COOLANT TEMPERATURE
600.0
550.0
500.0
450.0
Temperature (K)
0
200
400
600
800
1000
Time (seconds)
LEGEND
MSLB + 1 SGTR + HL Break
MSLB + 1 SGTR
MSLB + 5 SGTRs
620.6
530.6
440.6
350.6
Temperature (Deg F)
Time (seconds)
LEGEND
SGTR
4 Loop PWR 2 inch CL Break
FSAR MSLB

Fig. 2a.

Fig. 2b.



PRESSURIZER WATER LEVEL
Level (m)
Level (feet)
Time (seconds)
LEGEND
MSLB + 1 SGTR + HL Break
MSLB + 1 SGTR
MSLB + 5 SGTRs
SGTR
4 Loop PWR 2 inch CL Break
FSAR MSLB

Fig. 3a.

Fig. 3b.

SECONDARY SYSTEM PRESSURE

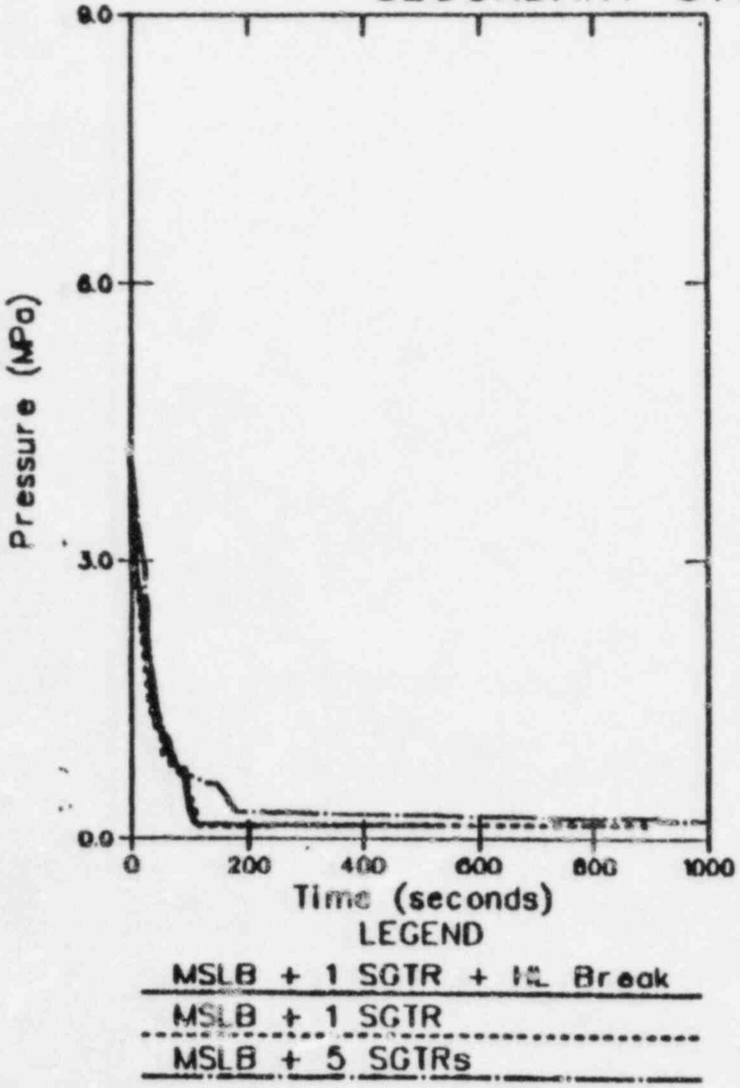


Fig. 4a.

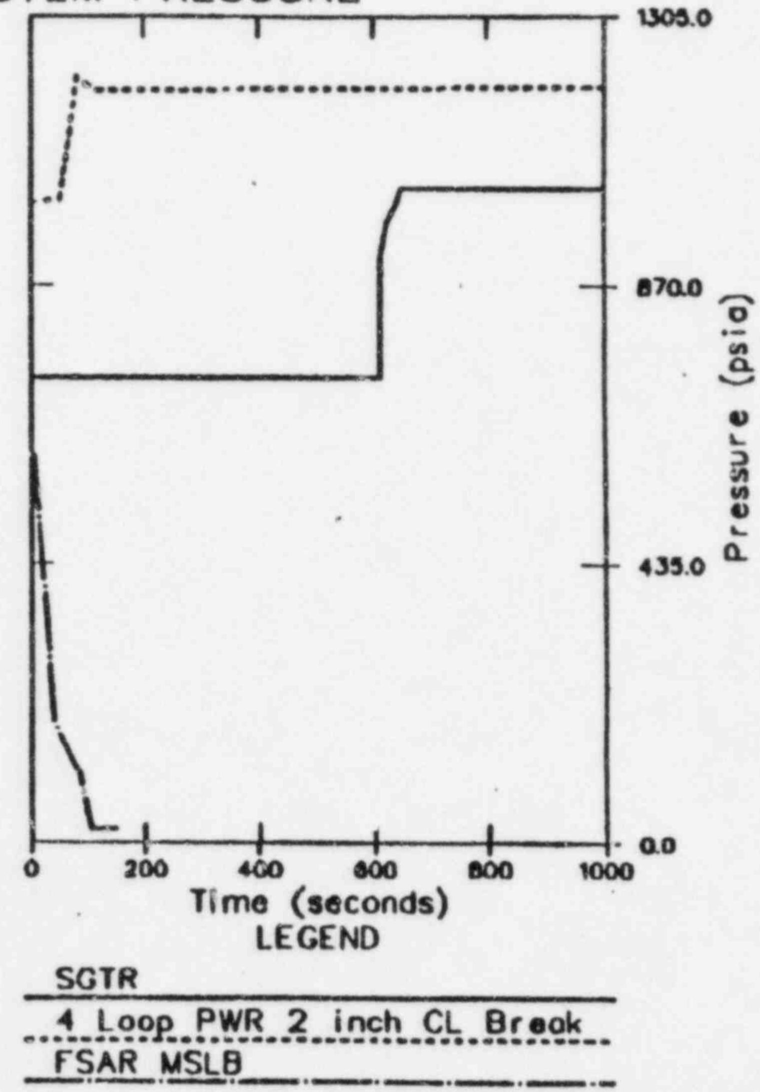
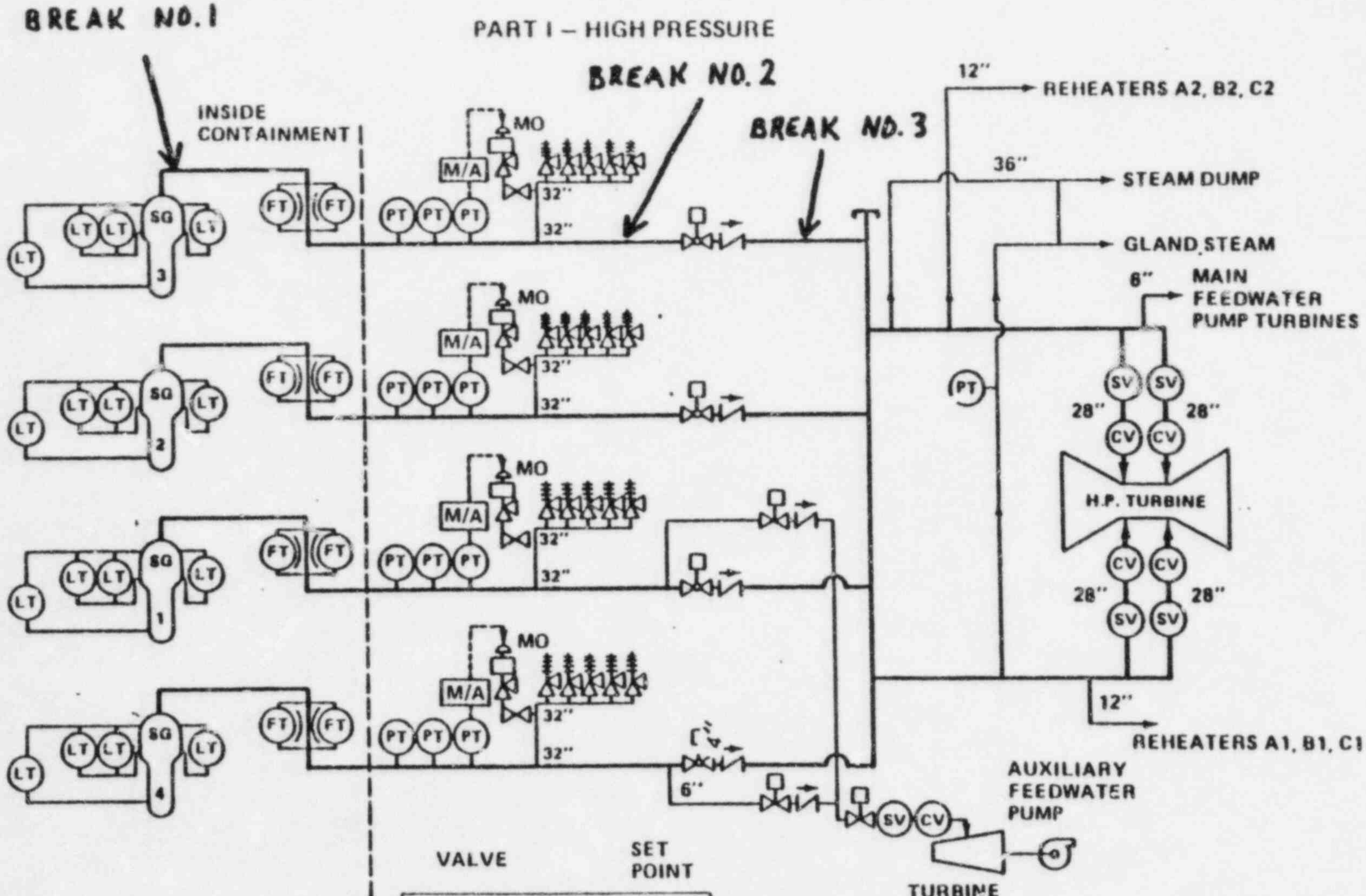


Fig. 4b.

MAIN STEAM

PART I – HIGH PRESSURE



VALVE	SET POINT
POWER OPERATED	1040 psig
SAFETY NO. 1	1064 psig
SAFETY NO. 2	1077 psig
SAFETY NO. 3	1090 psig
SAFETY NO. 4	1103 psig
SAFETY NO. 5	1117 psig

Fig. 5.