COMMITTEE ON INTERIOR AND INSULAR AFFAIRS
U.S. HOUSE OF REPRESENTATIVES
WASHINGTON, D.C. 20515

February 5, 1982

The Honorable Nunzio Palladino
Chairman
United States Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Chairman:

As a follow-on to the February 4 briefing, I would appreciate the Commission's answers to the following questions in addition to the information requested by Mr. Markey.

1. What is the primary significance of the Ginna incident?

2. What was the leak rate through the break as a function of time?

3. What triggered the steam generator tube rupture?

4. Had there been indications of leaking steam generator tubes prior to the rupture on January 25?

5. What was the cause of the PORV's apparent failure to close? Does the apparent failure of the PORV to close cause doubt about the adequacy of the industry's program to test such valves?

6. What would the course of the incident have been had the PORV block valve failed to close partially or fully following failure of the PORV to close fully?

7. Did the procedure for responding to a steam generator tube rupture contain instructions for actions to be taken in response to development of a steam bubble in the reactor pressure vessel?

8. Was there a need during the incident to take actions not specified in the plant's written operating and emergency procedures? Were the emergency procedures in place at Ginna consistent with Westinghouse guidelines as discussed in the January 28 memorandum from Mr. Speis to Dr. Mattson?

9. Had a water level measuring device been available, would it have assisted the operators in determining the size of the steam bubble in the pressure vessel and otherwise in

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10. What consideration has been given the potential for radioactivity escaping PWRs via a path including breaks in steam generator tubes and a stuck open safety valve.

11. Is it generally agreed that if a leak had developed in both steam generators, the operators would have been able to institute the "feed and bleed" process described in Mr. Speis' January 28 memorandum.

12. How many steam generator tube ruptures per year of the Ginna magnitude or greater do you expect?

13. What is the likelihood of several steam tube ruptures occurring at one time? What is the maximum number of simultaneous or near simultaneous steam generator tube ruptures that are considered design basis accidents following which the a can be brought to a safe shutdown condition by following plant operating and emergency procedures?

14. Did WASH 1400 or more recent risk assessments determine the probability of occurrence of events in which one or more steam generator tube failures are followed by various combinations of PORV, block valve, and safety valve failures?

15. How long did it take to reach cold shutdown? Is this a period longer than desireable? What was the reason for the period being longer than normal? What kinds of malfunctions during the extended cooldown period might have led to a significant release of radioactivity to the environment?

16. Did any part of the reactor pressure vessel cool at a rate in excess of that stipulated in the plant technical specifications?

17. Was there a capability at Ginna to remotely vent the reactor pressure vessel high points? Does the Commission believe that conditions might develop in PWRs calling for the use of remotely controlled valves for the purose of venting steam?

18. At any point during the Ginna event, did the steam generator containing the ruptured tube control the primary system pressure? Are operators at Ginna and other PWRs trained with respect to actions to be taken when a steam generator controls primary system pressure?

Sincerely,

Mo Udall

MORRIS K. UDALL
Chairman

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

MAR 19 1982

MEMORANDUM FOR: Thomas A. Ippolito, Chief
Operating Reactors Assessment Branch
Division of Licensing

FROM: Keith R. Wichman, Section Leader
Engineering Section
Operating Reactors Assessment Branch
Division of Licensing

SUBJECT: MEETING WITH WESTINGHOUSE ON STEAM GENERATORS

Attached is a summary of the subject meeting that was held on March 2, 1982 in Bethesda. Westinghouse presented their views with respect to steam generator tube degradation and steam generator tube rupture accident management. A list of attendees is shown in Enclosure 1 to the summary.

K R Wichman

Keith R. Wichman, Section Leader
Engineering Section
Operating Reactors Assessment Branch
Division of Licensing

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PDR

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MEETING SUMMARY DISTRIBUTION

NRC/PDR
Local PDR
TIC/NSIC/TERA
H. Denton
E. Case
D. Eisenhut
R. Purple
B.J. Youngblood
A. Schwencer
F. Miraglia
J. Miller
G. Lainas
R. Vollmer
J.P. Knight
R. Bosnak
R. Schauer
R.E. Jackson
OIE (3)
ACRS (16)
R. Tedesco
N. Hughes
V. Wilson

NRC Participants:

G. Lainas
S. Hanauer
L. Shao
C. McCracken
S. Reynolds
W. Johnston
T. Speis
K. Wichman
D. Eisenhut
R. Mattson
M. Williams
H. Conrad
J. Laaksonen
J. Mazetis
S. Newberry
W. Koo
E. Murphy
P. Matthews
S. Pawlicki
W. Hazelton
C. Cheng

G. Lear
W. Hazelton
V. Benaroya
Z. Rosztoczy
W. Haass
D. Muller
R. Ballard
W. Regan
R. Mattson
P. Check
O. Parr
F. Rosa
W. Butler
W. Kreger
R. Houston
W. Gammill
L. Rubenstein
T. Speis
W. Johnston
S. Hanauer
T. Murley
F. Schroeder
D. Skovholt
M. Ernst
K. Kniel
G. Knighton
A. Thadani
D. Tondi
J. Kramer
D. Vassallo
P. Collins
D. Ziemann
F. Congel
J. Stolz
M. Srinivasan
W. Minners
C. Berlinger
E. Adensam

Westinghouse Electric Corp.:

D. Rawlins
P. Rahe, Jr.
J. Esposito
O. Woodruff
D. Malinowski

SUMMARY OF MEETING WITH WESTINGHOUSE REGARDING

STEAM GENERATORS HELD ON MARCH 2, 1982

A meeting was held with Westinghouse representatives on March 2, 1982, in Bethesda, MD. The purpose of this meeting was to have Westinghouse present their views with respect to steam generator tube degradation and steam generator tube rupture (SGTR) accident management. A list of attendees is shown in Enclosure 1.

Westinghouse presented the steam generator configurations of various models with feed ring design and pre-heater design and identified the major differences among the models, especially with respect to the feedwater flow path. It was indicated that out of the five SGTR events experienced by Westinghouse steam generators in the past seven years, only two SGTR events are corrosion related. Two SGTR events are considered preventable because one event was caused by the presence of a foreign object and one was due to excess tube ovality in a tube fabricated by a foreign supplier. The latest SGTR event is still under study. Westinghouse also indicated that with 708,000 steam generator tubes in service, approximately 18,000 tubes (2.6%) were plugged and 45% of those plugged tubes were in four plants.

Steam generator tube degradation was classified into two groups (large leak and minor leak) based on the potential magnitude of primary coolant leakage. The types of tube degradation with the potential of causing a large leak are those at the U-bend apex area, those resulting from the presence of foreign objects, and IGA/SCC above the tubesheet. Other types of tube degradation resulting from denting; IGA attack in the tube sheet crevices and in the rolled tube; pitting; thinning; wear at anti-vibration bars (AVB) and the preheater baffle areas will in general, result in small leaks. Westinghouse considers the types of tube degradation with the potential of causing large leakage as mentioned above are controllable. Leakage from the U-bend apex can be prevented by plugging since experience has shown that this type of degradation usually occurs only in the tubes of first or second rows. Degradation due to the presence of foreign objects can be prevented by stringent administrative control of tools and materials used during secondary side maintenance and visual examination aided by advanced optical equipment for areas not directly accessable.

In addition, Westinghouse recommended the following methods to control crevice and sludge pile corrosion, (1) reduce the operating temperature for plants when such corrosion is evident, (2) sleeving, (3) reduce containment inventory by sludge lancing, isothermal soaks or depressured flushing.

In addition, Westinghouse recommended the following methods to control crevice and sludge pile corrosion, (1) reduce the operating temperature for plants when such corrosion is evident, (2) sleeving, (3) reduce containment inventory by sludge lancing, isothermal soaks or depressured flushing.

A brief status summary, based on inspections of 51 operating Westinghouse plants, was presented on the tube denting problem. It was indicated that 25 plants showed various degrees of denting activity; the rest did not show any sign of denting. Among the 25 plants, 12 plants are considered active, the other 13 plants are stabilized. Of the 12 active plants, Westinghouse rated denting in three plants as extensive and the other nine plants, minor.

Westinghouse recommended frequent monitoring of hydrogen content in the primary water as a means to estimate the extent of ongoing tube denting activities. This is based on the theory that the corrosion process associated with denting generates substantial amount of hydrogen in forming magnetite.

The guidelines for SGTR emergency response (EGR), which are sponsored by the Westinghouse Owners Group were presented. The basis for SGTR EGR's are operator intensive and include operating experience obtained from SGTR events. The status and issues in SGTR ERG review pertaining to pre-TMI guidelines (pre 3/28/79) and post-TMI guidelines were outlined. Items, issues, and guidelines, developed or to be developed, in Phase I ERG (11/81) and Phase II ERG (6/82) were discussed. Westinghouse also identified the areas to be emphasized in post Ginna Review of ERG which are, (1) a continuing effort to develop optimum ERG's and (2) review of ERG training methods.

Westinghouse concluded that the steam generator tube degradation problem is under control as demonstrated by the decrease in the number of tubes required to be plugged in recent years. Westinghouse also emphasized that out of the 18,000 plugged tubes which is 2.6% of the total tubes in service, 45% are in four plants.

Since the information presented by Westinghouse was proprietary, Westinghouse agreed to document the information pursuant to 10 CFR 2.790.

K Wichman

Keith R. Wichman
Operating Reactors Assessment Branch
Division of Licensing

Enclosure:
1. Attendance List

ATTENDANCE LIST

MEETING WITH WESTINGHOUSE

MARCH 2, 1982

NRC Participants

G. Lainas, DL
S. Hanauer, DST
L. Shao, RES
C. McCracken, CMEB
S. Reynolds, Region I
W. Johnston, DE
T. Speis, DSI
K. Wichman, DL
D. Eisenhut, DL
R. Mattson, DSI
M. Williams, DL
H. Conrad, CMEB
J. Laaksonen, DSI
J. Mazetis, DSI
S. Newberry, DST
W. Koo, DL
E. Murphy, DE
P. Matthews, DE
S. Pawlicki, DE
W. Hazelton, DE
C. Cheng, DE

Westinghouse Participants

D. Rawlins
P. Rahe, Jr.
J. Esposito
O. Woodruff
D. Malinowski

ACRS Participant

E. Igne

OFFICE OF THE CHAIRMAN

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

March 22, 1982

The Honorable Morris K. Udall, Chairman
Committee on Interior and Insular Affairs
United States House of Representatives
Washington, DC 20515

Dear Mr. Chairman:

This is in response to the questions posed in your February 5, 1982 letter relative to the recent event at the R. E. Ginna Nuclear Power Plant. Our responses to your questions are enclosed.

As a consequence of this event, I, too, have questions on the incident and its generic implications and have, on January 29, 1982, requested the staff to establish a Task Force to review and evaluate the Ginna incident. An interim report from that effort is expected to be completed this month and may provide detailed answers to some of your questions. The remainder of your questions are addressed in the enclosure.

Sincerely,

Nunzio J. Palladino

Nunzio J. Palladino
Chairman

Enclosure:
Responses to Questions

cc: Rep. Manuel Lujan

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PDR/LPDR

QUESTION 1. What is the primary significance of the Ginna incident?

ANSWER

The primary significance of this event is that it apparently occurred without advance warning and challenged the ability of the plant and operators to respond in a safe manner. It also points out the inadequacies in the steam generator inspections; i.e., the licensees do not inspect the secondary sides of steam generators, with the exceptions of a few plants that have suffered extensive tube denting and support plate cracking. The safety objective in such an event is to prevent fuel damage and to allow only minimal releases of radioactive materials to the environment. The tube failure, whether it be the result of chemical or metallurgical reasons, or some type of mechanical unloading mechanism, has not yet been determined. The failure mode and the plant and operator responses will be addressed in the NRC Task Force 45-day report.

QUESTION 2. What was the leak rate through the break as a function of time?

ANSWER

The attached graph (Figure 1) is our preliminary estimate of the leak rate as a function of time, calculated from information provided by the licensee.

FIGURE 1

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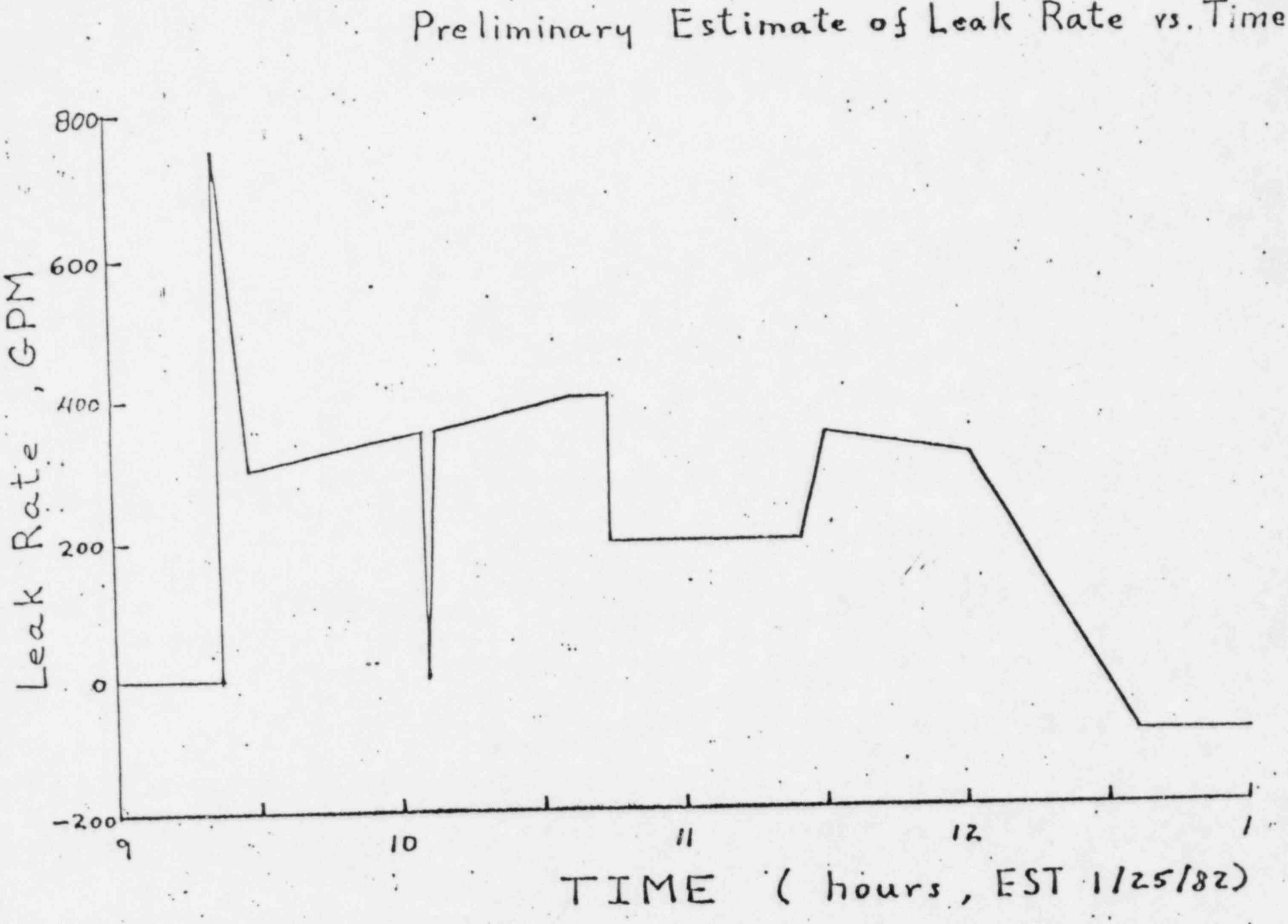

QUESTION 3. What triggered the steam tube rupture?

ANSWER

The licensee is continuing his inspection of the steam generator to determine the cause of the failure. This inspection will include removing sections of several tubes, including the ruptured tube, for laboratory examination.

QUESTION 4. Had there been indications of leaking steam generator tubes prior to the rupture on January 25?

ANSWER

A table of the history of steam generator tube inspection and plugging through May 1981, which includes leakage experience, is attached as Table 1. Although preliminary information from the licensee stated that the failed tube was not leaking immediately prior to the tube rupture, whether there was any indication of such leakage will be addressed in our 45-day report.

TABL 1.

STEAM GENERATOR TUBE INSPECTION AND PLUGGING HISTORY

Date	No. Tubes Inspected A/B Hot	No. Tubes Inspected A/B Cold	Primary to Secondary Leakage, gpm	Total Defects A	Total Defects B	Type of Degrad.	No. Defects Requiring Repair A	No. Defects Requiring Repair B	No. Tubes Plugged/Sleeved/Pulled A	No. Tubes Plugged/Sleeved/Pulled B
In Factory			----	1	--	---	1	--	1/--/--	--/--/--
04/72	1050/----	----/----	----	0	0	---	0	0	0/--/--	0/--/--
03/74	3259/1098	516/ 516	----	19	0	a	19	0	19/--/ 2	0/--/--
11/74	1707/ 672	430/ 39	----	2	0	a	2	0	2/--/--	0/--/--
03/75	2174/1931	442/ 442	0.0050 A S/G	46	11	b/a	46	11	46/--/ 2	11/--/--
01/76	----/ 53	----/----	0.091 B S/G	0	2	a	0	2	0/--/--	2/--/--
02/76	3192/3247	3192/3247	----	39	2	a	39	2	39/--/--	2/--/--
04/76	100/1025	----/ 75	0.099 B S/G	0	15	b	0	15	0/--/--	15/--/--
04/77	2003/1525	268/ 268	----	13	1	a	13	1	13/--/--	1/--/--
07/77	----/ 300	----/----	0.012 B S/G	--	5	b	--	5	--/--/--	5/--/--
01/78	----/ 350	----/----	0.060 B S/G	--	8	b/a	--	8	--/--/--	8/--/--
04/78	2049/1714	325/ 375	----	1	15	b	1	15	1/--/--	14/--/ 1
02/79	2049/1714	325/ 375	----	--	6	b/a/c	--	6	--/--/--	6/--/--
12/79	----/1200	----/----	0.007 B S/G	--	13	c/a	--	13	--/--/--	13/--/--
04/80	3139/3182	325/ 375	----	1	31	d/c	1	13	1/--/--	28/--/ 3
11/80	3138/3151	325/ 375	----	--	3	c	--	2	--/--/--	0/ [illegible]/--
05/81	3138/3141	325/ 400	----	--	15	c/a	--	6	--/--/--	1[illegible]/ 3
				122 or 3.7%	127 or 3.9%		122 or 3.7%	99 or 3%	122/--/ 4 or 3.7%	106/21/7 or 3.5%

Type of Degrad.

- a - Wastage
- b - Cracking
- c - ID Cracking
- d - IGA
- e - Pitting
- f - Fatigue Cracking (B&W)
- g - Erosion/Corrosion (B&W)

QUESTION 5. What was the cause of the PORV's apparent failure to close? Does the apparent failure of the PORV to close cause doubt about the adequacy of the industry's program to test such valves?

ANSWER

Ginna's power operated relief valve (PORV) uses pressurized "control" air to remotely operate the valve. Control air is routed through solenoid pilot valves which in turn pressurize one side of a flexible diaphram in the PORV's valve operator and simultaneously vent the other. The differential pressure across the diaphram causes it to flex and in turn moves the valve's stem and disc. If shut, the valve is held shut by an internal spring and air pressure. If open, the valve is held open by air pressure alone. Based on information provided at an NRC meeting with the licensee on February 10, 1982, the failure of the PORV to close resulted from a failure of a solenoid valve in the control system of the PORV. The failure was related to a modification of the solenoid valve that was made specifically for the Ginna PORV control system. The function of the failed solenoid valve is to open and relieve air pressure, thus permitting the PORV to close when signaled to do so. At Ginna, the failed solenoid valve is physically located within the pressurizer enclosure some distance from the PORV and is not considered to be a part of the PORV itself.

The PWR utilities, in response to one of the Commission-approved NRC Action Plan Items (i.e., Item II.D.1, NUREG-0660), funded the Electric Power Research Institute (EPRI) to conduct qualification testing of full-size prototypical PORVs and safety valves. The testing of the PORV's in the EPRI program was completed as of the end of August 1981. The PORVs were tested for open and closure capability for a variety of fluid conditions, proposed by the utilities and EPRI as generically representative of the types of fluids PORVs could be exposed to under transient or accident conditions.

The NRC staff reviewed and commented on the EPRI program as it was being formulated. During this review, and during the development of the Action Plan requirement, the problems of including PORV control systems in the program were specifically discussed. In addition to the enormous complexity involved in including as many control systems in the test program as there are PWR plants, it was also recognized that the PORV control system elements are not directly furnished by the valve manufacturer with the valve. For these reasons the PORV control system was not included in the generic PORV test program. However, the lessons learned from the malfunction of the air-operated control system for the PORV will be factored into a current evaluation which is assessing the need for improving air systems serving components and systems important to safety. In addition, the potential for accidents or transients being made more severe as a result of control system failures or malfunctions is being addressed in Unresolved Safety Issue A-47, "Safety Implications of Control Systems."

QUESTION 6. What would the course of the incident have been had the PORV block valve failed to close partially or fully following failure of the PORV to close fully?

ANSWER

Had the block valve failed to close after the PORV stuck open, the additional coolant loss from the primary system would have caused the primary system pressure to continue to decrease below approximately 900 psi. As the pressure in the reactor system decreased, the combined leak flow (through the valve and the rupture) would decrease and safety injection flow would increase until the flows were approximately equal. Analyses by Westinghouse in WCAP-9600 [1/] indicate that the reator system pressure would stabilize at approximately 700 psi. The pressure would then remain relatively constant until the operator took action to depressurize the plant with the intact steam generator. If the block valve were only partially closed, the combined leak flow and safety injection flow would equalize at a pressure between 700 psi and the 1300 psi which was reached at Ginna after the block valve was fully closed. Additional leakage out of the reactor system through the broken tube in the isolated steam generator would not occur for the case of the block valve stuck fully open since the primary system pressure would be less than the affected steam generator pressure. If the block valve were only partially closed, the reactor system might be pressurized so that the leakage would be less than that which occurred with the block valve fully closed.

The effect on core coolant inventory of a combined PORV leak and steam generator tube leak would be similar to a postulated break in the reactor coolant hot leg with an equivalent break size of about 2 1/2 square inches. The consequences of this event on core cooling would be bounded by the spectrum of small break analyses performed for Ginna. [2/] These analyses demonstrate that the core is adequately protected by the emergency core cooling system in the event of a small break LOCA.

The staff preliminarily concludes, based on the discussions above, that the effect of the block valve failing to close or leaking during the event at Ginna would have been a decrease in coolant loss through the steam generator tube and an increase in coolant loss through the PORV. Since coolant loss through the PORV is confined within the containment building and coolant loss through the broken tube may be released through the secondary system safety valves, off-site doses would probably have been lessened had the block valve stuck open at Ginna. Small break LOCA analyses for Ginna indicate that the core would be adequately cooled had the block valve failed to close. However, the dual break situation would have been more complex for the operators to diagnose and would have introduced the added difficulty of more water and radioactivity being released inside containment.

1/ Report on Small Break Accidents for Westinghouse NSS System, WCAP-9600, Westinghouse Electric Corporation, June 1979.

2/ Letter from LeBoeuf, Lamb, Leiby & MacRae, Attorneys for Rochester Gas and Electric Corporation, to L. Muntzing, U. S. AEC, transmitting small break LOCA analyses for Ginna, September 6, 1974

QUESTION 7. Did the procedure for responding to a steam generator tube rupture contain instructions for actions to be taken in response to development of a steam bubble in the reactor pressure vessel?

ANSWER

Based on preliminary information from the licensee, we understand that the Westinghouse Guidelines were used (Revision 1, April 1980) for developing plant-specific procedures and did not contain specific instruction for responding to a steam bubble in the reactor pressure vessel head area; therefore, they were not included in the Ginna procedures. However, based on special training and their knowledge of the TMI event, the operators were able to recognize the existence of the steam bubble through observation of the rapid increase in pressurizer level and reactor vessel head temperatures in conjunction with reactor coolant system pressure which indicated saturated steam conditions existed in the head area. Furthermore, readings from the core exit and vessel upper head thermocouples in conjunction with the primary system pressure confirmed that the steam bubble was confined to the head area.

A full review of the Ginna procedures is being conducted, and the results will be included in the 45-day report.

QUESTION 8. Was there a need during the incident to take actions not specified in the plant's written operatir; and emergency procedures? Were the emergency procedures in pla:e at Ginna consistent with Westinghouse guidelines as discussed in the January 28, memorandum from Mr. Speis to Dr. Mattson?

ANSWER

Plant operator response to the event, including the use of procedures, is being reviewed and the results will be included in the 45-day report. The emergency procedures in place at Ginna were based on the Westinghouse Guidelines Revision I dated April 1980.

The discussion of the event in the subject January 28, 1982 Speis memorandum concerned proposed Westinghouse guidelines dated September 1981 which are currently under review by the NRC staff. Further discussion is provided in enclosure 8-1 (SECY 82-58) dated February 10, 1982).

QUESTION 9. Had a water level measuring device been available, would it have assisted the operators in determining the size of the steam bubble in the pressure vessel and otherwise in bringing the plant to a stable condition?

ANSWER

There are several types of water level indication systems being considered by industry and the NRC staff with respect to assisting the operator in making determinations of inadequate core cooling. Some of these systems include level indication in the reactor vessel head region. Had such a measuring device been installed, it likely would have been an aid to the operator. The operators, however, did use the available instrumentation (pressurizer level, reactor coolant system pressure, and vessel upper head thermocouples) in making determinations of the existence of the steam bubble in the reactor vessel head. Furthermore, the core exit thermocouple readings in conjunction with the reactor coolant pressure confirmed that the steam bubble was confined to the reactor vessel head area and took actions accordingly.

QUESTION 10. What consideration has been given the potential for radioactivity escaping PWRs via a path including breaks in steam generator tubes and a stuck open safety valve?

ANSWER

Steam generator tube rupture accidents are one of the class of design basis accidents considered by applicants and staff in each review of PWR license applications. The staff's Standard Review Plan, NUREG-0800, describes the criteria and procedures used at Section 15.6.3, "Radiological Consequences of Steam Generator Tube Failure (PWR)".

The analysis focuses on the potential release of radioactive noble gases and radioiodine both pre-existing in the reactor primary and secondary coolant, and generated concurrently with the accident. The former case uses the maximum activity levels permitted by the plant's proposed Technical Specifications. The latter case postulates activity released from the fuel as a result of the accident, including the potential for fuel failures.

The steam generator tube failure is assumed to be a double ended rupture of a single tube for purposes of calculating the rate of transfer of primary coolant to the secondary side of the affected steam generator. Flashing of the primary coolant is assumed to occur in this process with subsequent atomization and transfer of activity to the steam phase. Radioactivity entering the steam generator from the primary system is assumed to leave the steam generator, become airborne immediately, and be transported directly to the atmosphere via leakage paths not mechanistically specified. Such leakage could be through a stuck open safety valve, an open atmospheric dump valve, or through the condenser vent system. For FSAR safety analyses, such releases are assumed to occur during the first 30 minutes of the event, after which credit for operator action is allowed to terminate releases.

Exclusion area boundary and low population zone boundary doses are calculated and compared with the thyroid and whole body dose guideline values cited in 10 CFR Part 100. Conservative values of site specific atmospheric dispersion characteristics are used in these calculations.

The system response to the event postulated in this question is not covered by the Standard Review Plan. However, it is being considered in the preparation of new emergency procedure guidelines per TMI Action Plan item I.C.1.

QUESTION 11. Is it generally agreed that if a leak had developed in both steam generators, the operators would have been able to institute the "feed and bleed" process described in Mr. Speis' January 28 memorandum?

ANSWER

Had a leak developed in the second ("A") steam generator at Ginna, the need to institute the "feed and bleed" process to assure continued core cooling would have depended upon the leak size and total leak rate of primary coolant out of the primary system. It is uncertain whether the operators would have been able to institute "feed and bleed" for reasons described below.

The primary concern associated with two leaking generators is that in order to use the steam generators to cool down the primary system to the residual heat removal (RHR) system entry level, the primary system pressure would have to remain slightly higher than the pressure in both faulted generator secondaries during cooldown. This would result in continued leakage of primary coolant to the secondary system. Primary coolant would have to be replaced by the high pressure injection (HPI) system which pumps water from the refueling water storage tank (RWST) into the primary system. Thus, there is an amount of leakage that eventually affects the ability to cool the plant to RHR entry conditions prior to depleting the RWST. This behavior is different than other small loss-of-coolant accidents in the primary system. In those accidents leaking water will accumulate in the containment sumps. Once the RWST level drops to a preset value, the pump suction is switched from the RWST to the sump and sump water is recirculated through the core. Decay heat is ultimately removed by the containment heat removal system.

For larger tube leaks in both steam generators, which might deplete the RWST inventory prior to RHR entry conditions being reached, the operators would be expected to open all PORVs, essentually the same effect as causing a small break LOCA inside containment. This would rapidly depressurize the primary system (as well as remove decay heat) to below the faulted steam generator secondary pressures. In parallel with this action the operators would isolate both steam generators. Primary coolant makeup would be accomplished with the HPI pumps.

At Ginna, a two-loop 1300 MWth Plant, there are two PORVs manufactured by Copes-Vulcan with a relief capacity of 179,000 lb/hr. steam. Although neither the staff nor the licensee has performed any detailed calculations, scoping estimates indicate that the Ginna plant can remove decay heat by the "feed and bleed" process. It should be pointed out that in order to establish "feed and bleed," the operator must first establish PORV operability. In the case of Ginna, this involves reestablishing the air supply to the PORV which was initially isolated on low pressure safety injection actuation.

ANSWER 11 (CONTINUED)

At Ginna, there are procedures in place which instruct the operator on how to reset the safety injection signal in order to enable reestablishing the air supply necessary for PORV operability. This procedure was, in fact, used in reestablishing instrument air which allowed the initial operation of the PORV at Ginna during the tube rupture event.

Additionally, there is a backup nitrogen system which is manually controlled from the control room which can be used to actuate the PORVs in the absence of normal instrument air.

It is noted that failures in both steam generators are not required in the design basis for PWRs. Furthermore, existing emergency procedures, such as those at Ginna at the time of the tube rupture accident, do not provide the operators with explicit guidance on how to cooldown the plant with ruptures in multiple steam generators. However, as a result of the TMI accident, the staff's TMI Action Plan item I.C.1 requires the industry to upgrade emergency operating guidelines and procedures to cover multiple failure events. One of the specific events cited in NUREG-0737 is tube failures in multiple steam generators. Significant resources to the upgrading of guidelines and procedures have been allocated by both the industry and the staff. We anticipate approving the new emergency procedure guidelines by the end of FY 82. If this goal is met, upgraded procedures should be implemented at all operating plants by FY 83.

QUESTION 12. How many steam generator tube ruptures per year of the Ginna magnitude or greater do you expect?

ANSWER

There have been four steam generator tube failures of this type (greater than 50 gpm) at pressurized water reactors in the U. S. to date. The facility, date of the event and estimated leakage rate is as follows:

Plant	Date	Gallons/Minute (Maximum)
Point Beach Unit 1	02/26/75	125
Surry Unit 2	07/15/76	80
Prairie Island Unit 1	10/02/79	390
Ginna	01/28/82	700

The above data indicates that for all 48 PWRs licensed to operate in the U. S. (as of February 1), about one tube failure has been occurring every two years since 1975. The leakage rate from the Ginna failure is approximately the maximum possible for a single tube failure; therefore, leakage much in excess of this amount is not expected.

The technical resolution of Unresolved Safety Issue A-3,4,5, "Steam Generator Tube Failure," is in its final stages of development and includes consideration of recommendations for improvements in inservice inspection, steam generator secondary water chemistry monitoring and turbine condenser inspection. These improvements when completed should lessen the overall problem of tube corrosion. However, these changes, when implemented, are not expected to eliminate totally the possibility of future tube failures.

QUESTION 13. What is the likelihood of several steam tube ruptures occurring at one time? What is the maximum number of simultaneous or near simultaneous steam generator tube ruptures that are considered design basis accidents following which the reactor can be brought to a safe shutdown condition by following plant operating and emergency procedures?

ANSWER

Experience to date indicates that multiple tube failures is a low probability event.

As was discussed in our response to question 10, the steam generator tube rupture that is postulated to establish the design basis for the plant is the equivalent of a double-ended rupture of a single tube. For design base purposes, this is considered to encompass a spectrum of smaller leaks in either single or multiple tubes.

It is our belief that plants can most likely accommodate a larger number of tube failures, 1/ without exceeding the capacity of the ECC systems and without leading to core damage. Consequential radiological releases would also be calculated to increase. However, the radiological source would still be due to the induced primary coolant activity and not from fission products released due to gross fuel failures resulting from the event.

In addition to the tube rupture used for establishing the plant design basis, emergency operator guidelines and procedures presently being upgraded as a result of the TMI-2 accident will address methods for managing ruptures in multiple tubes and multiple generators. (See response to Question 11 last paragraph).

1/ We interpret the second part of the question to mean tube ruptures alone, not to be concurrent with or as a consequence of design base accidents (either primary system loss of coolant accident or main steam line break). The tolerable number of tube ruptures concurrent with or as a consequence of design basis accidents is rather small, dependent on the plant thermal hydraulic design and the design basis accident in question. However, we expect the tolerable number of tube ruptures would most probably be much larger for more likely accidents or transients.

QUESTION 14. Did WASH-1400 or more recent risk assessments determine the probability of occurrence of events in which one or more steam generator tube failure(s) are followed by various combinations of PORV, block valve and safety valve failures?

ANSWER

Steam generator tube rupture alone has been considered in PRA's as one of several types of small-break accidents to which pressurized water reactors may be subject. Multiple tube ruptures and ruptures in more than one steam generator have not been considered in PRA's nor have combinations of other component failures such as those identified in the question been considered. We are now taking a more careful look at these scenarios.

QUESTION 15. How long did it take to reach cold shutdown? Is this a period longer than desirable? What was the reasons for the period being longer than normal? What kinds of malfunctions during the extended cooldown period might have led to a significant release of radioactivity to the environment?

ANSWER

The plant was in cold shutdown the day following the vent (6:53 p.m.). The time from reactor trip to cold shutdown was 33 hours 25 minutes.

The period from reactor trip to cold shutdown was no longer than desirable. In fact, there was no urgent need to reach cold shutdown conditions, especially after the steam generator tube leak had been terminated (equalizing primary pressure with the faulted steam generator) and the plant was in a stable shutdown condition. This stable safe shutdown was reached about two and half hours after the reactor trip.

In general, it is expected that cooldown with a ruptured tube in one steam generator would be significantly slower than a normal cooldown. This slower cooldown is because the reactor coolant system pressure is to be equalized to the pressure in the ruptured steam generator to minimize or terminate reactor coolant leak flow through the rupture. Since the direct release of steam from the ruptured steam generator is to be minimized (the steam would contain radioactive products from the primary system), depressurizing the faulted steam generator must be by other less direct means. In Ginna, the steam generator with the ruptured tube was drained to the reactor coolant system through the ruptured tube. Additional cooling and depressurization was provided by cold auxiliary feedwater which replaced part of the drained water. The length of time for the cooldown was primarily governed by the management's desire to go slowly and cautiously. The time to reach cold shutdown was consistent with the plant's condition and, therefore, no longer than desirable.

If there had been no steam release from the ruptured steam generator in the early stage of the event, it is reasonable to expect the cooldown period would have been longer. For a large initial steam space in the ruptured steam generator, a limiting factor for steam generator draining is need to keep the steam generator tubes covered. Should the steam come in direct contact with the tubes, rapid condensation would occur resulting in a rapid depressurization of the ruptured steam generator secondary side and re-initiation of reactor coolant leakage back through the ruptured tube.

During most of the extended cooldown period at Ginna, the ruptured steam generator was isolated and its pressure was significantly lower than the safety valve set pressure. All other steam valves from the steam generator were secured. The reactor coolant system was controlled similar to a normal cooldown, except for measures (increased letdown, boration) to accommodate the leak flow to the primary system coming from the secondary side.

As indicated in the response to Question 10, potential releases of radioactivity to the environs during the short term or long term most directly relate to additional malfunctions in the faulted steam generator. Such leakage could be through a stuck open safety or relief valve flow path or through the condenser vent system. For Final Safety Analysis Report radiological safety analyses, such releases are assumed during the first 30 minutes of the event, after which credit for operator correction is allowed.

QUESTION 16. Did any part of the reactor pressure vessel cool at a rate in excess of that stipulated in the plant technical specifications?

ANSWER

Analysis of information to determine specific cooldown rates is being conducted and will provided in the 45-day interim report.

QUESTION 17. Was there a capability at Ginna to remotely vent the reactor pressure vessel high pcints? D-s the Commission believe that conditions might develop in PWRs calling for the use of remotely controlled valves for the purpose of venting steam?

ANSWER

The physical capability existed at Ginna but was not declared operational since staff review is not complete. The reactor vessel head vent system, including associated hardware and control system, has been installed at Ginna. Before the staff authorizes use of the installed vents, we will review not only the design but also the associated procedures which are to specify when to vent and when not to vent. Procedural guidelines for venting is an integral part of our review of transients and accidents. We expect to complete procedural reviews in FY-1982, and finish designs for all PWRs in FY-1983.

In PWRs with inverted U-tube steam generators (i.e., Westinghouse and Combustion Engineering reactors), high point vents are required to be located on the vessel head. This requirement was added for the purpose of providing a vent path for non-condensible gases that could accumulate in the primary system under degraded core cooling conditions. Although these vents could be used to vent steam which might accumulate in the vessel upper head after saturation conditions are reached in parts of the vessel, it is not expected they would be used for this purpose, nor is it recommended that they be used to vent steam. Steam in the upper head of Westinghouse and Combustion Engineering reactors does not pose a direct threat to continued core cooling. If the steam bubble were to expand to the hot leg outlets, it would most likely condense as it came into contact with subcooled water exiting the core. If, for any reason, the water exiting the core was saturated, the steam would enter the hot leg pipes and travel to the steam generators, where it would be condensed.

For events such as the one at Ginna, the method preferred for removing steam which accumulates in the upper head of the vessel is to restart a reactor coolant pump. The pump will force subcooled water into the upper head region and condense the steam bubble. The operators at Ginna demonstrated the capability to do this following the formation of a steam bubble in the upper head.

In PWRs with once-through steam generators (OTSGs) (i.e., B&W reactors), a steam bubble in the upper head of the vessel has the potential to temporarily interrupt natural circulation if it expands and is able to enter the hot leg outlets without condensing. Pursuant to item II.B.1 of the TMI Action Plan these plants will eventually have high point vents installed on the top of the hot leg inverted U-bends. In addition, some utilities with B&W reactors will install vents on the top of the vessel head.

Analyses by B&W have indicated that interruption of natural circulation is a temporary phenomenon. The analyses show that system repressurization following the interruption of natural circulation will ultimately produce thermal-hydraulic conditions in the primary system which restore natural circulation. The staff is still reviewing the capability of the B&W analysis methods to properly predict the relevant thermal-hydraulic phenomena.

ANSWER 17 (CONTINUED)

B&W has recently recommended use of the hot leg high point vents to vent steam. which may accumulate during the recovery phase of a small break loss-of-coolant accident (SBLOCA). During the accident phase of a SBLOCA, B&W has recommended the "bumping" of the reactor coolant pumps to sweep any steam trapped in the hot leg high points into the steam generator.

The use of the high point vents to vent steam in B&W reactors, as well as the acceptability of the B&W calculational models to properly predict the thermal-hydraulic behavior of the primary sytem under two-phase conditions, is under active staff review. At this point in the review, it is our preliminary conclusion that the use of the vents in B&W reactors to remove steam which accumulates at primary system high points may be the preferred method of steam removal if a reactor coolant pump cannot be restarted and run continuously.

QUESTION 18. At any point during the Ginna event, did the steam generator containing the ruptured tube c.ntrol the primary system pressure? Are operators at Ginna and otner PWRs trained with respect to actions to be taken when a steam generator controls primary system pressure?

ANSWER

In order to prevent further contamination and to aid in cooling down the faulted steam generator, a feed and bleed operation was used. This operation consisted of providing feedwater to the faulted steam generator in order to maintain level within a desired band; a steam bubble in the steam generator was maintained during this period. As a result of primary system pressure control by the operators through the use of the normal charging/letdown systems and by controlling the cooldown rate through the "A" steam generator, primary system pressure was decreased in a controlled manner. Pressurizer level was maintained and primary system pressure was controlled by the pressurizer. However, during this period the plant was controlled in such a manner as to result in an inflow of water from the "B" steam generator to the primary system through the ruptured tube.

This area, specifically during the early part of the transient, is being reviewed further and the results will be included in the 45-day report.

The operators at PWRs are trained to maintain control over both primary and secondary system pressure following a steam generator tube rupture. The goal is to minimize flow between the two systems by maintaining the two systems within 50 psi of one another.

February 10, 1982

SECY-82-58

POLICY ISSUE
(Information)

For: The Commissioners

From: William J. Dircks, Executive Director for Operations

Subject: MEDIA ATTENTION TO A PRELIMINARY EVALUATION OF OPERATOR ACTIONS DURING THE GINNA EVENT

Purpose: To inform the Commission of the preliminary evaluation.

Discussion: On January 28, 1982, three days after the steam generator tube rupture event at the Ginna reactor, the Reactor Systems Branch in the Office of Nuclear Reactor Regulation completed a preliminary evaluation of the event. The purpose of the evaluation was to compare operator action and plant response at Ginna to the recently proposed Westinghouse emergency procedure guidelines for steam generator tube rupture events. A copy of the resulting staff memorandum is attached. Some of the results of the preliminary evaluation were briefly noted by NRR (Roger Mattson) at the Commission briefing on January 28, 1982. A copy of the memorandum was also provided to Region I staff at that briefing.

A story on this memorandum appeared in the February 8, 1982 New York Times (also attached). There are two erroneous impressions left by the Times article. First, it fails to note that in the memorandum the operator actions were compared to new, not existing, emergency procedure guidelines for Westinghouse reactors. The new guidelines are currently under review by the Reactor Systems Branch. They were not being used by the Ginna operators and they will likely be changed significantly before being eventually approved and implemented at operating plants.

Second, the Times article makes the memorandum appear to conflict with other statements by NRC that the Ginna operators

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PDR/LPDR

performed well. The memorandum says "it is premature to judge whether (a) the operator actions were correct, incorrect, or could stand improvement, and (b) whether the (new) emergency guidelines are correct or not." The memorandum was speaking for the Reactor Safety staff in the Division of Systems Integration of NRR which, at that time, had not received a copy of the actual Ginna procedures or a written chronology of the events of January 25. Obviously it was premature then for that staff to make a judgment on the correctness of operator actions. They offered none. Neither did they contradict the Regional Administrator's statements that were based on first-hand access to the necessary information. By failing to make this distinction, the Times article implies a division of opinion between the Reactor Safety staff of the Division of Systems Integration and Regional Administrator when, in fact, none exists.

William J. Dircks
Executive Director for Operations

Attachments:
1. 1/28/82 Staff Memo
2. 2/8/82 Times Article

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

DRAFT

JAN 28 1982

MEMORANDUM FOR: Roger Mattson, Director, Division of Systems Integration

FROM: Themis P. Speis, Assistant Director for Reactor Safety, DSI

SUBJECT: PRELIMINARY EVALUATION OF OPERATOR ACTIONS FOR GINNA SG TUBE RUPTURE EVENT

Based on the chronological listing of the Ginna events you provided us on 1/26/82, which we understand was provided by R. Starostecki of Region I, I have asked Jukka Laaksonen and Brian Sheron to compare the operator actions and plant response to the Westinghouse Emergency Operator Guidelines for Steam Generator Tube Rupture Events. This comparison is provided in Enclosure 1. These guidelines are called EOI-0 and EOI-3. We used the latest version presently under review by the staff as part of TMI Action Plan Item I.C.1. However, the technical guidance is generally the same as the earlier versions the staff reviewed and approved for the pilot monitoring program for NTOLS. However, we do not know if the emergency procedures in place at Ginna at the time of the accident were derived from or were consistent with these guidelines.

Our preliminary conclusion is that the operator acted properly in using the PORV to depressurize the RCS to the pressure of the faulted steam generator. SI termination was also accomplished consistent with the guidelines, although it may have been delayed longer than necessary and resulted in a brief discharge of the "B" (faulted) generator to the atmosphere. The fact that the PORV stuck open complicated the scenario by producing a rapid depressurization which led to flashing of the upper head fluid. We also note that the SI pump was restarted at 11:15 a.m., which resulted in a second lifting of the "B" generator safety valves. The reason for this action is unclear.

One observation we drew from this action is that operators appear to be very hesitant to terminate HPI when they are allowed to, or even are supposed to. We point this out since, for the pressurized thermal shock issue, the industry has tried to convince us that operators would always terminate HPI before the primary system was unacceptably repressurized.

Another observation is that the operators tripped the RCPs according to present instructions, and restarted the A Loop RCP when allowed. A discussion on the RCP trip criteria is provided in Enclosure 2.

A number of other preliminary observations were made of the Ginna event which, I believe, warrant further investigation. These are:

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1. Stratification of the faulted steam generator - The faulted steam generator was being cooled and depressurized by the primary system. There was some evidence, based on thermal-hydraulic conditions of the system, that significant stratification of the secondary coolant in the faulted generator occurred. This resulted in the water in close proximity to the tubes cooling down, but leaving a layer of hot water "insulating" the steam in the steam dome from the cold water. Thus, depressurization of the faulted generator seemed to proceed slower than expected. It is not yet clear what safety significance is associated with this phenomenon.

2. Additional coolant system failures

   a) Leak in "A" Loop SG

   If a leak also developed in the "A" loop steam generator, then primary coolant would continue to leak to the secondary, unless both SGs were isolated. Decay heat removal would then need to be accomplished by "feed and bleed" (HPI for coolant addition; PORV for coolant discharge). (Westinghouse, in their latest guidelines, recommends cooldown using the steam generator with the lowest level and probably the smallest leakage.)

   b) Stuck-open secondary side safety/relief valve

   A stuck-open secondary side safety/relief valve in the faulted generator would produce a direct path for primary coolant to enter the atmosphere. Moreover, the present emergency procedures probably do not address this scenario. The primary coolant would have to be made up with HPI water. If the leak was not stopped, or additional cooling water supplies were not made available, then eventually all of the HPI water from the refueling water storage tank would be exhausted and a net loss of primary coolant would occur. Without corrective action, core uncovery would eventually occur.

3. Loss of steam-jet air ejectors

   The loss of the steam jet air ejectors due to low "A"-loop SG pressure (< 150 psi) produced a loss-of-condenser vacuum and required decay heat removal by steaming to the atmosphere. Reasons why the A loop pressure was dropped so low, the reasons why the air ejectors were lost, and the significance of this in the course of the accident will have to be addressed.

I believe it is premature to judge whether (a) the operator actions were correct, incorrect, or could stand improvement, and (b) whether the emergency guidelines are correct or not. This is because they are designed to cover a multitude of scenarios, in which the Ginna accident was just one.

RSB has been addressing a similar scenario in response to an AEOD concern. RS will continue to investigate the above areas of concern, as well as any others brought to our attention, and recommend action as appropriate.

Themis P. Speis, Assistant Director
for Reactor Safety,
Division of Systems Integration

Enclosures:
As stated

cc: H. Denton
E. Case
D. Eisenhut
S. Hanauer
R. Vollmer
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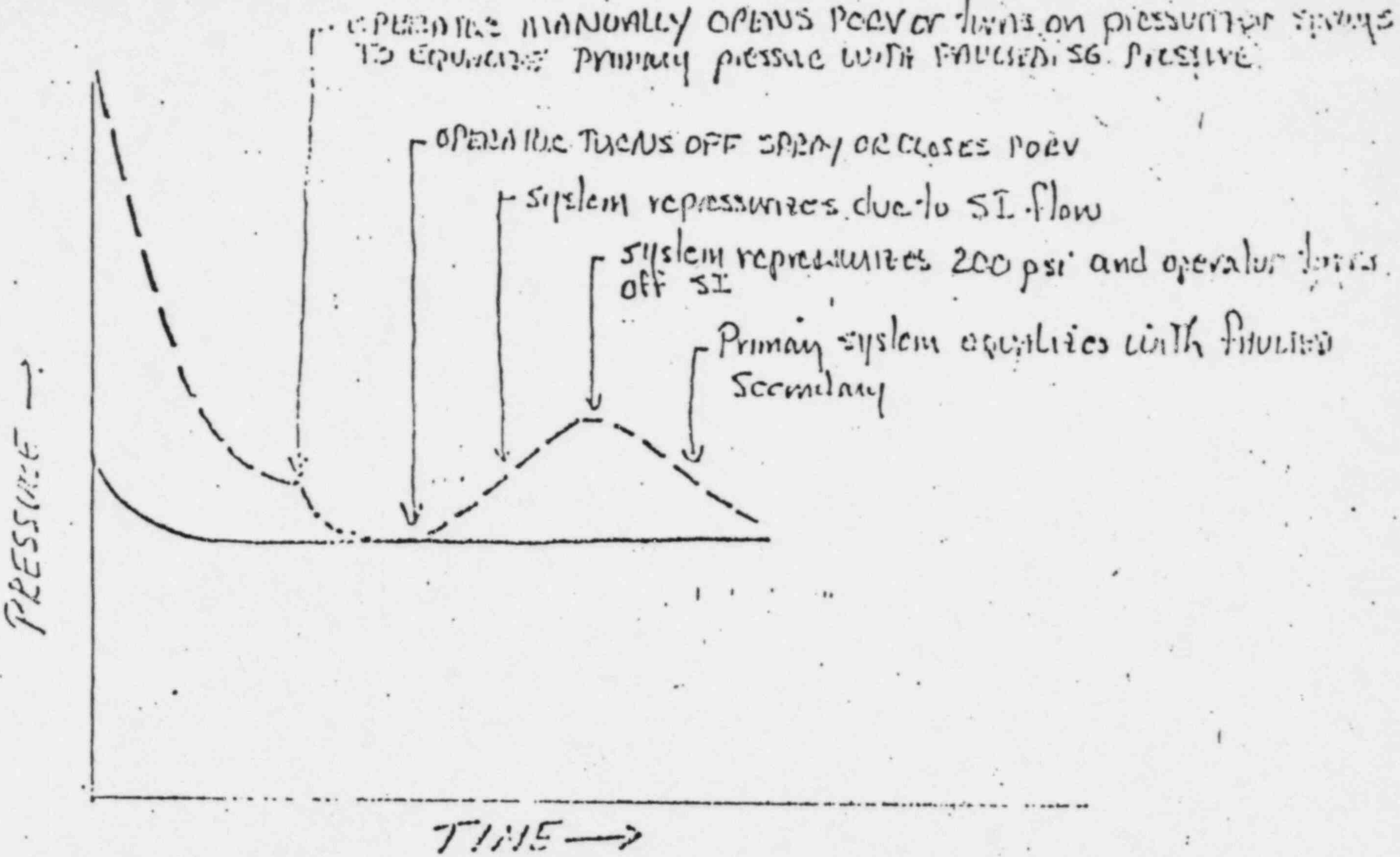

Primary System Pressure Behavior (Expected) for SGTR based on Guidelines for Operator Action

- - - - - Primary System Pressure

———— Secondary System Pressure - Faulted Steam Generator

TIME	EVENT/OPERATOR ACTION	REMARKS- These remarks are based on the generic W Emergency Operator Guidelines for Steam Generator Tube Rupture Events presently under staff review.
9:25	SG tube rupture in SG B, indicated by charging pump high speed, SG high level, steam/feedwater mismatch, air ejector radiation	
9:28	Reactor Trip on low pressure, SI signal on low pressure, containment isolation resulting in loss of instrument air and normal charging flow and RCP seal flow	Reactor Tripping on low pressure and fast depress[urization indicate a severe rupture; Westinghouse r[esults] for a double-ended one tube rupture do not show as large depressurization.
9:29	Pressurizer level off-scale low, RC pressure decreased to 1200 psi	RCP trip criteria are met, the operator should tr[ip] the pumps manually
9:33	Operator trips RCP's	Correct action, delayed 4 minutes
9:40	Operator closes main steam isolation valve at the faulted SG B	The event has been diagnosed and the faulted SG ha[s] been identified from increasing level and pressur[e] and the first corrective action is as told in the guidelines. It is unclear if the auxiliary FW to faulted SG is stopped and if all isolation valves [of] the steam lines are closed.
9:46	RC pressure 1200 psi, RC average temperature 475°F	Reactor coolant temperature indicates that fast cooling in compliance with the guidelines is in progress.
9:53	Good SG A at 540 psi, level 76%, steam dumped to the condenser, natural circulation in loop A, faulted SG B at 826 psi, level 89%	The status of SG A and the loop A is as told in [the] guidelines. The initial cooldown of the RCS is al[most] completed. At this stage the operator should st[art] depressurizing the RCS to the SG B pressure to s[top] the tube leakage. Because the RCPs are off the [PORV] should be used. However, PORV is not available because of isolated instrument air system. Faul[ted] SG pressure is surprisingly low and indicates la[ck of] proper isolation.
9:57	Operator resets SI, pumps still on, instrument air re-established	At this stage, the operator is able to depressur[ize] the RCS, but he does not do that. Thus, the lea[k] continues and SI is needed to keep the RCS inven[tory]

TIME	EVENT/OPERATOR ACTION	REMARKS
10:04	Charging pumps restarted, RCS at 1300 psig, pressurizer level 18%, SG B level 100% narrow range, 400 inches wide range	Restart of charging pumps before stopping the tu leak is not in compliance with the guidelines an leak increases because the charging pumps increa RCS pressure. SG B filling up is a consequence failure to depressurize the RCS.
10:07	Operator opens the PORV manually	The action is taken somewhat too late
10:08	Operator opens the PORV manually for a second time, PORV sticks open	If the PORV is opened on time there is no reaso multiple PORV operation.
10:09	PORV block valve shut, RCS pressure 800 psi, pressurizer level offscale high.	Correct action to shut block valve. Drop in RC pressure to 800 psi flashes hot liquid to steam RPV upper head, pushing water into pressurizer
10:10	SI pumps increase the pressure to 1300 psi	After having closed PORV the operator is instruc see if the system repressurizes. If pressure in creases 200 psi, then the SI can be turned off. to stuck open PORV, the ability of the operator t follow this guidance is questionable.
10:18	T_{incore} = 458°F	Adequate subcooling
	Atmosperic relief valve on SG B isolated manually	Precaution against opening
10:30	$T_{PV\ head}$ = 525°F (p sat=850 psi)	Not clear if upper head bubble condensed out. Temperature supports existence of bubble
10:40	Safety valve of the SG B blows, operator secures the SI to reset the SI	Safety valve blowing is a direct result of secur the SI about 30 minutes too late
10:42	RCS at 800 psi	There is obviously almost no steam bubble in the ssurizer and the pressure decreases drastically w some water is drained from the system. Pressure stabilizes to a value where the water in the up head starts to flash. It is unclear how primary is lost because the faulted SG B should be at ab safety valve set pressure (above 1000 psi).
10:50	RC pump seal return relief valve lift and discharge to the PRT	Reason for relief valve opening unclear, possibl related to the containment isolation

TIME	EVENT/OPERATOR ACTION	REMARKS
10:57	PRT rupture disc blows, total loss of coolant ~ 8000 gal	PRT overpressure results from combined PORV and seal return relief valve operation
11:15	SI pump started, SG B safety valve lifts at 1035 psi (set pressure 1085 psi)	Reason for SI start unknown, SI re-initiation criteria are not met (loss of sub-cooling, pressurizer level<20%); when did the safety reset?
11:15	T_{cold} on operable loop was higher than core exit TC's	Reason unknown
11:22	RPV head at 525°F, 97°F subcooling, pressure 1035 psi	
11:29	RCP in loop A restarted, core exit and upper head thermocouples equalize at 450°F	The guidelines tell to start at least one RCP after the initial plant stabilization and SI termination, restart may be delayed because o problems with seal injection
12:00	Pressurizer level 80%	
12:05	Normal letdown established	Normal letdown/charging is told to be establi as the next step after SI termination
12:30	Slow cooldown started, RCS at 923 psi	
6:40	Level in SG B re-established, SG cooled by adding cold auxiliary feedwater	SG B depressurization is obviously no problem because there is not much steam left
7:05	RHR initiated, RCS at 280 psi, 330°F	

There are a number of questions that can be raised by the pump trip issue. The RCP trip criterion for W plants is that the operators should trip all RCPs if SI has actuated and the primary system pressure has dropped below a specified value. This value (or rather the method by which this value is obtained) was worked out and mutually agreed upon between W and the staff during the B&O Task Force after the accident at TMI. Essentially, the value is the set pressure of the secondary safety valve plus adders to account for pressure drops back to the pressure gauge in the control room. Typical values are expected to be between 1350 and 1450 psi. A more detailed discussion of this pressure setpoint derivation is provided in Section 7.2.2 of NUREG-0623 (Attachment 1).

It is noted that the charging flow at Ginna is isolated on an ECCS signal. Since seal injection flow to the RCPs is from the charging flow, it too is lost during an ECCS signal. Thus the pumps would be required to be tripped following the ECCS signal, regardless of the pump trip criteria.

For any steam generator tube rupture which depressurizes the primary system to below the RCP trip pressure, there would be a need for the operator to use the PORV to aid depressurization, since the primary system pressure will stabilize slighty above the faulted steam generator secondary pressure. For a smaller leak, the RCPS would not be tripped immediately, and the sprays would remain available to aid in the depressuri ation. For CE and B&W plants, the RCP trip criterion is on low pressure SI actuation (around 1600-1750 psi). Thus earlier RCP trip would be expected for both these plants. Both CE and B&W were asked informally to adapt the W low pressure criterion, but both declined.

Section 6.0 of NUREG-0623 recommended that the industry develop RCP trip criteria which minimized RCP trip for non-LOCA transients (see Attachment 2) and also recommended that procedures and training be initiated for handling non-LOCA events which produce ECCS actuation and pump trip, including instructions for:

a) tripping RCPs;

b) monitoring and initiating natural circulation;

c) pressure control without pressurizer spray;

d) HPI termination;

e) RCP restart criteria.

Attachment 3 provides section 7.2.5 of NUREG-0623.

The reasons for requiring RCP trip are as follows:

- For certain small breaks in the primary system, continuing RCP operation will "pump" water out of the break, and produce a greater coolant inventory loss than if the pumps were tripped.

- For any small break in the primary system, including steam generator tube rupture, the coolant will become two-phase and could evolve to a significant void fraction. We are not aware of any RCP's that have been designed to operate for extended periods of time in a highly voided system. Continued operation in a highly voided system could result in excessive vibration and possible seal failure, or worse.

- During the initial phase of many transients and accidents, the symptoms may resemble those of a small break or a steam generator tube rupture. Early RCP trip with restart instruction is considered the most prudent course of action.

- Analysis models which predict system performance with a small break and the RCP's operational still have large uncertainties when the system void fractions are high. Thus we do not have a high confidence that pump failure during high void conditions does not lead to unacceptable core uncovery.

7.2 Short-Term Requirements

The following describe the short-term requirements for pump trip for each of the reactor vendors.

7.2.1 Control Room Operators

IE Bulletins 79-05C and 79-06C (item 1.B) require that two licensed operators be in the control room at all times (three for a dual control room) and that one of the two operators be designated to trip the reactor coolant pumps should the facility undergo a transient which results in a safety injection actuation signal due to low primary system pressure. The designated operator may perform any normal or routine control room duties at all other times. The licensee should confirm that an operator is designated to perform this action on each shift.

7.2.2 Westinghouse-Designed Plants

For the short-term, the staff has adopted the following position for manual pump trip requirements on Westinghouse-designed plants.

Staff Position on Pump Trip for Westinghouse Plants

We require that the reactor coolant pumps be tripped at a system pressure determined in the following manner:

(1) Secondary System Pressure - Based on the number and size of the secondary system safety valves, the secondary pressure will be established by determining the pressure setpoint for that valve in which the calculated steam relief is less than 60 percent of the valve's relief rating. If the calculated relief is greater than 60 percent of the rated capacity, then the next highest pressure setpoint should be used.

(2) Primary to Secondary Pressure Difference - To account for the pressure gradient needed for heat removal, pressure drop between the steam generator and safety valves, uncertainty of the safety valve setpoint, pressure drop from steam generator to measurement location, etc., the primary pressure for RCP trip should be the secondary pressure as established by (1), above, plus 100 psi if the calculated adjustments are 100 psi or less. If the adjustment are determined to be greater than 100 psi, the larger value should be used.

(3) Instrument inaccuracies appropriate to that time in the loss-of-coolant accident should be added to the primary pressure established in (2), above. The resulting pressure is the indicated pressure at which the operator should trip the RCPs.

7.2.3 Combustion Engineering-Designed Plants

Combustion Engineering has recommended that reactor coolant pump trip be manually initiated by the operator on receipt of reactor trip and safety injection actuation signals. Combustion Engineering is also evaluating the capability of their plants to accomodate a pump trip on reactor trip and a lower system pressure by a method similar to that established for Westinghouse as specified in Section 7.2.2, above.

The staff will accept the pump trip based on reactor trip and SI actuation for the short-term, since SI actuation pressure is approximately 1550 to

LOCA can result in a greater mass inventory loss from the system than if the pumps were tripped.

(2) The ability to correctly represent the thermal-hydraulic behavior in key components within the primary system during a small break LOCA with the reactor coolant pumps running is questionable. Moreover, it is unclear at this time which models clearly result in conservative, bounding calculations: This is substantiated by the variety of different models used to represent the various primary system components in vendor analyses and the differences in the limiting small break analyses. It is our conclusion that this uncertainty in thermal-hydraulic modeling presently precludes the use of these models for quantitative determination of small break system behavior with the coolant pumps running. In particular, we cannot accept their use to substantiate allowable modes of pump operation during small break LOCAs.

(3) It is our conclusion that for the pumps running case, insufficient integral system experimental data presently exists to substantiate the quantiative results of the analysis codes. Moreover, we do not believe any proposed testing can be performed on a schedule compatibl with that necessary for short-term resolution, which includes the addition of equipment necessary to assure automatic tripping of the coolant pumps for small break LOCAs.

(4) From items (2) and (3), above, we find that tripping all of the reactor coolant pumps during small break LOCAs is required at this time, and that this pump trip should be automatically initiated from equipment that is safety-grade to the extent possible.

(5) The impact of an early pump trip on non-LOCA transients is not predicted to lead to unacceptable consequences. However, tripping the reactor coolant pumps for non-LOCA transients can aggravate the consequences of these transients and extend the time required to bring the plant into controlled shutdown condition. For B&W plants, tripping of the reactor coolant pumps during severe overcooling events increases the potential for interruption of natural circulation due to steam formation in the coolant loops.

Therefore, we conclude that the criteria and requirements for reactor coolant pump trip to be established from item (4), above, should minimize, to the extent practicable, the probability of initiating a reactor coolant pump trip for non-LOCA transients.

(6) The staff recognizes the potential desirability of running the reactor coolant pumps to provide forced circulation during small break LOCAs and we encourage the continued exploration by the industry of means by which this could be accomplished. For example, an increase in HPI capacity or two-pump operation as proposed by Combustion Engineering are a step in this direction.

(7) We will require verification of small break models with the pumps running against appropriate integral systems experimental tests. In particular, we will require that the PWR vendors and fuel suppliers

1600 psig for CE plants as compared to SI actuation pressures of about 1800 to 1900 psig for Westinghouse plants. It is expected that the pressure used for pump trip by Westinghouse will fall approximately in the range of the safety injection actuation pressure for both CE and B&W plants.

7.2.4 Babcock and Wilcox-Designed Plants

Babcock & Wilcox is also recommending that for the short term, pump trip be manually initiated on automatic actuation on low pressure of the safety injection system. In addition, Babcock & Wilcox and their plant owners are examining the possibility of a short-term manual trip requirement based on subcooling rather than automatic SI actuation on low pressure only. The staff agrees in principle with this approach, but final approval must wait until the details of such a method have been formally submitted and evaluated.

The staff finds the present short-term requirement for manual trip on automatic SI actuation on low pressure acceptable. B&W SI actuation setpoints are between 1500 psig and 1650 psig and are considered consistent with the setpoints at which the pumps would be tripped for both Westinghouse and Combustion Engineering plants.

7.2.5 Training Guidelines and Emergency Procedures

IE Bulletins 79-05C and 79-06C (items 3 and 4) requested the Westinghouse, Combustion Engineering, and Babcock & Wilcox plant licensees to:

(1) Develop new guidelines for LOCA and non-LOCA events based on LOCA analyses and RCP trip requirements, and

(2) Revise emergency procedures and train all licensed operators and senior reactor operators based on these new guidelines.

In general, the licensees have identified guidelines, procedures, and training for loss of coolant events in their responses to these items. This effort on LOCA events was already in progress at the time the bulletin was issued.

Because of the potential for initiating ECCS by other depressurization events such as overcooling because of a malfunction in the secondary system, the operator would have to trip the reactor coolant pumps before he could make a determination about what event is occurring. As a result, we require that the licensee have procedures and operator training to handle non-LOCA events which may also have ECCS actuation and reactor coolant pump trip.

The procedures for these non-LOCA events should include instructions on tripping the reactor coolant pumps, monitoring and initiating natural circulation, pressure control without the pressurizer spray, HPI termination criteria, and reactor coolant pump restart criteria. The licensees should confirm that these procedures for non-LOCA events are in place and the operators have been trained in their implementation.

By MATTHEW L. WALD

Special to The New York Times

WASHINGTON, Feb. 7 — Radioactivity was released into the atmosphere during the recent nuclear accident at the Robert E. Ginna plant because operators were "too late" in turning off emergency pumps, according to a preliminary evaluation by a staff member of the Nuclear Regulatory Commission.

A second release occurred 35 minutes later because operators restarted the pumps for "unknown" reasons, the study found.

Chronology of Accident

The evaluation said it was "premature" to judge whether actions by operators were "correct, incorrect or could stand improvement." However, its author and other officials of the commission maintained today that the operators had handled the accident well. A spokesman for the Rochester Gas and Electric Company, Judy Houston, said that the utility had not seen the document and therefore could not comment on it.

The evaluation also points to problems in the safety systems of the plant, a Westinghouse design in common use, which made the accident harder to control. One major plant component used to regulate the pressure in the reactor was disabled by a combination of safety actions, according to a chronology of the accident that is part of the evaluation.

The evaluation, which is stamped "draft," was written by Themis P. Speis, assistant director for reactor safety of the Division of Systems Integration. The division is studying the problem of automatic reactor systems that interact in unexpected ways and cause problems in emergencies.

The accident on Jan. 25 at the plant, 16 miles northeast of Rochester, resulted in the uncontrolled release of a small amount of radioactivity, although such releases have been avoided during similar accidents at other plants. The amount of radiation released was not dangerous, according to plant and commission officials.

According to Mr. Speis's memo, the Ginna accident raises the specter of far more serious accidents, some of which are not anticipated by current emergency procedures. For example, remarks accompanying the chronology of events imply that a crucial safety valve may briefly have stuck open, and if it had stayed open, according to the analysis, it is not clear how damage to the reactor's core would have been prevented.

In addition, the hesitancy of the operators to turn off certain safety pumps in this case raises the possibility that in future cases, where such a shut-off would be more important, the pumps would be left on and pressure would rise so high that the reactor vessel itself, which holds the fuel, might be cracked.

Mr. Speis's memorandum stops short of referring to the actions of the operators as errors. However, his chronology of the accident notes decisions made by operators that resulted in the leak running faster, and in a safety valve "blowing" twice and allowing radioactive steam to vent into the atmosphere.

The accident began at 9:25 A.M. in one of Ginna's two steam generators. At Ginna and at 48 other plants of its type around the country, radioactive water is circulated around the hot uranium core, and then pumped through thousands of narrow tubes, where it gives off its heat. Outside the tubes, clean water is boiled into steam, which is used to run a turbine.

The radioactive water, at temperatures over 500 degrees Fahrenheit, is kept under pressure to prevent boiling. What happened at Ginna is that one of the tubes burst, allowing the pressurized radioactive water to squirt into the clean steam, at 700 to 800 gallons per minute. Released from its pressurized environment, the water turned to steam in the steam generator. The pressure from the extra steam forced open a relief valve, which vented outside the containment building.

Certain safety steps, it is clear in retrospect, aggravated the problem. Automatically, the reactor's control system sensed the loss of water in the radioactive loop and turned on emergency pumps to add water. In many cases, this is a necessary step to insure that the core remains covered with water. If the core is uncovered, as happened at Three Mile Island, the resulting heat will damage it.

Pumps Left on Longer

In the Three Mile Island case, the accident was compounded by the operators' decision to turn off the emergency pumps. At Ginna, the pumps were left on longer. Turning them off "may have been delayed longer than necessary and resulted in a brief discharge" to the atmosphere, the analysis said. The valve that allowed the radioactive steam to escape opened the first time as a "direct result" of shutting down the pumps "about 30 minutes too late," according to the analysis.

A second release came when the pumps were restarted, according to the analysis, which said the reasons for this action are "unknown."

Ronald C. Haynes, a commission official who was at the scene on the day of the accident, said that even though restarting the pumps resulted in a release of radioactivity, it was a "conservative" step, because the operators thought it would reduce the possibility of core damage.

The analysis said that "operators appear to be very hesitant" to turn off the pumps "when they are allowed to, or even supposed to."

In addition to these actions by the operators, the design of the reactor seems to have made their job more difficult.

For example, when the leak began and the reactor shut down, another system automatically began closing valves and shutting down parts of the plant considered nonessential in an emergency. One of those parts provided compressed air to operate a valve that can be used to reduce the pressure of the radioactive water, a useful step if there is a leak.

Shut Down Pair of Pumps

Also as a safety step, the operators shut down a pair of pumps that, among other functions, can be used to cool water in the pressure-controlling device and thereby lower the pressure.

The operators restarted the air line to the valve that relieves pressure on the radioactive water, but did not open the valve until 42 minutes after the accident began. "The action is taken somewhat too late," remarks the evaluation's running commentary on the chronology. The valve was then closed, but the pressure was still too high.

One minute later, the operators opened the valve a second time, and it stuck open. The analysis remarks that if the valve had been opened on time, there would have been no reason to open it a second time.

The analysis says that the chain of events in the Ginna accident raises the possibility of other combinations of failures that could be more serious.

For example, the chronology raises the question of why pressure dropped so sharply when the safety valve on the steam generator allowed the first release to the atmosphere, implying that the valve may have stayed open slightly longer than it was supposed to. Among the points that the analysis says "warrant further investigation" are what would happen if such a valve stuck in the open position and produced "a direct path for primary coolant to enter the atmosphere." According to the analysis, "The present emergency procedures probably do not address this scenario."

In such a situation, unless the leak could be stopped or a new supply of water could be found, the emergency pumps would continue to add water, which would be pumped through the burst tube or other leak, turned into steam and released to the environment, until the emergency system had no more water left, and "a net loss of primary coolant would occur. Without corrective action, core uncovery would eventually occur."

The result of "core uncovery" is core damage, the most serious kind of accident.