Westinghouse Electric Corporation Power Systems

Box 355
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November 13, 1979

NS-TMA-2156

Darrell G. Eisenhut, Director
Division of Operating Reactors
U.S. Nuclear Regulatory Commission
7920 Norfolk Avenue
Bethesda, Maryland 20014

Subject: Event Evaluation Reports

Dear Mr. Eisenhut:

During the past several months, abnormal events have occurred at several nuclear power plants with Nuclear Steam Supply Systems designed by Westinghouse. These events include sudden and significant steam generator tube leaks at the Doel plant in Belgium and at Northern States Power's Prairie Island plant Unit No. 1, and a stuck open condenser steam dump valve following a turbine trip at North Anna Unit No. 1. These events did not result in any abnormal radioactivity releases and would have probably received very little attention prior to Three Mile Island.

We now feel that significant benefits can be realized by more in depth evaluation of certain of these kinds of events with follow-up communication of the evaluation, findings and recommendations to all owners of Westinghouse plants, at a minimum. In our view, this information can be well utilized in utility operator training programs and in reviews of operating, abnormal and emergency procedures. Some of the findings could also result in future system or equipment modification.

We have completed the event evaluations for the Doel and North Anna transients and we expect to complete the Prairie Island report shortly. I am enclosing copies of

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both of the completed reports which have already been transmitted to Westinghouse customers. My reason for doing so is two fold. First, we would like some feedback on the format and content of the reports. Second, we would like some recommendations regarding further distribution of such reports to others in the industry and the manner in which that should be accomplished.

Very truly yours,

T. M. Anderson, Manager
Nuclear Safety Department

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Enclosure

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EVALUATION OF LICENSEE EVENT AT WESTINGHOUSE OPERATING PLANT

Operating Plant - Doel #2
Operating Utility - EPES
Date of Event - June 25, 1979

INTRODUCTION

The Doel #2 plant is located in Belgium and began commercial operation in late 1975. The Doel plant is a two loop 370 MWE PWR using the basic Westinghouse design. The detailed design was performed by Westinghouse Nuclear Belgium.

I. Description of Event

The description of the event is taken from the EBES Report of Incident Doel 2 letter OPS/JDW/79/4361. Attachment 1 is a copy of this report.

A. Plant Operating Conditions

The plant was heating up the primary loop after a repair of the pilot system on a main steam valve.

At the time of the event, the primary temperature was 491°F and the pressure had reached its value of 2232 psi. The reactor was subcritical with all rods inserted.

The secondary pressure in the steam generators was 640 psi, i.e., saturation pressure of 491°F.

Steam generator "A" has had low activity on the secondary side (less than allowable limit) for some time, which indicates a small primary to secondary leak.

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B. Sequence of Events

1. About 7:20 p.m., a quick depressurization was established in the primary loop, about 28 psi per minute. This caused an acceleration of the working charging pump. A second charging pump was started manually. The letdown line isolated automatically. The closed position of the pressurizer relief valves was confirmed and their isolation valves were preventively shut. The level in the pressurizer quickly dropped and the heaters switched off automatically.

   A quick level rise was also noted in steam generator "B". The radiation monitor of the blowdown line indicated a maximum activity.

   A combination of these indicated a leak in the tubing in steam generator "B". Immediately, steam generator "B" was completely isolated and the atmospheric steam relief valve set point was adjusted to a maximum setting.

   Concurrently, the third charging pump was also started (pump was administratively out of service in preparation for inspection). The three charging pumps were not able to make up the leakage in the steam generator. The CVCS tank was very quickly emptied and the charging pumps' suction was automatically diverted to the RWST.

   To increase the cooldown, the primary pump "B" was stopped and atmospheric steam release was started via steam generator "A".

2. Initiation of the Safety Injection

   About 20 minutes after the beginning of the incident, the pressure setpoint (1685 psi) of safety injection was reached. All the emergency diesels ran within the required time, but were not required to take the load. Isolation Phase A and isolation of the ventilation of the containment were initiated. The essential items, which had not been run, were started.

At 1535 psi, all the high pressure S.I. pumps (3 + 1 standby) discharged into the primary loop, whereby the depressurization was stopped.

To prevent the secondary pressure in the defective steam generator from reaching the set pressure of the safety valves, the primary pressure was reduced by maximum spraying in the pressurizer by restarting the primary pump B and using both the spraylines. During this phase, the level in the pressurizer rose very quickly and was completely filled. The spray was stopped and the pressure stabilized on the zero flow pressure of the high pressure S.I. pumps.

The automatically started auxiliary feed system provided an RCS depressurization in steam generator "B".

The auxiliary feed pump of the isolated S.G. was locally stopped and isolated. This was not possible from the control room because the S.I. signal had not been interrupted. The auxiliary feedwater tank was filled from DOEL 1.

3. Interruption of S.I. Signal

The interruption of S.I. had to be initiated to depressurize the plant. This was necessary for the following reasons:

a. To avoid opening of the safety valve of the steam generator.

b. To be able to use, as soon as possible, the RHR system (low pressure loop) in order to stop the blowdown of the steam via steam generator "A".

First, the safety injection signal had to be interrupted. This had to be done several times, with a five minute delay time each time, because permissive relay P11 was forgotten to be deleted. This gave prompt S.I. again after the interruption.

After successful interruption of the S.I. signal, two high pressure S.I. pumps were stopped and, shortly after, the third one was stopped. In accordance with the cooldown margin, the last high pressure S.I. pump was then stopped. Herewith, the pressure dropped to 924 psi. Saturation pressure was, at that moment, < 213 psi.

The letdown line valves were activated to open, but the valves remained closed. After a short investigation, it was realized that by isolating Phase A, the service air in the containment was also isolated. After realignment of the service air, the letdown line was operable. When the letdown line opened, the pressure dropped quickly at first, then gradually.

The loss of service air resulted in the CCW valves to the primary pumps closing. The pumps ran during this time without cooling of the thermal barrier. This did not cause the thermal barrier temperature to reach the alarm temperature. The water and oil coolers of the RCP are on separate circuits with motor operated valves and were unaffected by Phase A isolation.

4. Initiation of RHR System

The automatic isolation (valve RC 003) of the RHR system occurs at 398 psi. Since the depressurization rate was very slow through the letdown line, the changeover was effected at a pressure of 440 psi. There was enough margin with respect to the allowed pressure (597 psi) for this loop. This operation allowed steam relief from steam generator "A" to be stopped quicker and limited the release of steam.

5. Further Action

With the last mentioned operation, the primary pressure dropped below the secondary pressure in the defective steam generator "B". The secondary level dropped. This caused a dilution risk. The boric acid concentration was checked every half an hour. The concentration remained stationary at 1500 ppm.

The cooling down caused the pressure in steam generator "B" to drop slowly and fall below the primary pressure. From this point, the primary pressure was carefully held above the steam generator pressure. Despite the cold water that entered the steam generator this way, the pressure dropped very slowly. This was caused by a warm water layer at the top fo the generator that was unaffected by the cold water injection.

When the level in the steam generator approached the top of the wide range lev·l instrument, the pressure was sufficiently lowered (170 psi) to add nitrogen. The secondary drain pipes were connected to the system for liquid waste and the steam generator was emptied using the nitrogen pressure.

The nitrogen cushion itself had a low enough radiation level to be released via the interspace (volume between containment walls).

C. Environmental Impact

The incident was controlled properly, so that there were no prejudicial effects to the environment or the installation.

II. Evaluation of the Event

Westinghouse evaluation of the event has identified the following important factors:

1. Very early in the procedure, the primary pump "B" was stopped in order to increase the plant cooldown capability. Is this necessary and/or desirable for incorporation in the emergency procedure? The Westinghouse recommended procedure is to trip the RCP's when RCS pressure drops below 1250 psi plus indicated inaccuracy, if CCW to the pumps is lost, <u>or</u> during recovery according to the procedure after the plant has been stabilized at reactor coolant temperature 50°F below no-load temperature. Review of the Westinghouse

recommended instructions in this regard indicates that it is not neces· ·y to trip reactor coolant pumps in order to establish this level of reactor system cooldown. Furthermore, the recommended instructions are intended to address the possibility of event mis-diagnosis. In this case, the RC pump trip for accident recovery considerations has been intentionally placed as late as possible in the procedure to keep overall recovery instructions as similar as possible to those for LOCA and loss of secondary coolant.

2. In order to isolate auxiliary feedwater flow to the affected steam generator, a local manual operation was performed to stop the pump (because S.I. was not reset). Auxiliary feedwater flow to a steam generator can be be stopped from the control room without reset of the S.I. signal by use of the feedwater control valves. In fact, the auxiliary feedwater pumps do not need to be stopped to accomplish feedwater isolation of the affected steam generator.

3. The comment was made that P11 had to be deleted in order to effectively stop operation of the high pressure S.I. pumps. A review was made of the logic required for S.I. termination which showed that P11 does not need to be reset in order to effectively reset S.I. and stop high head S.I. operation. This has subsequently been clarified as a relay timing problem at DOEL and not a generic design feature.

4. The atmospheric steam relief valve setpoint was turned to a maximum as one of the early actions taken at DOEL to prevent/minimize steam relief through the affected steam generator.

The steam relief valves are currently set approximately half way between no-load pressure and shell side design pressure. As such, they are normally set only about 50 psi below the pressure at which the steam generator safety valves begin to open. Therefore, resetting their setpoint to a maximum results in very little increase in actual pressure margin available.

Furthermore, if steam relief would occur from the steam generator, it would be less desirable that such relief occur through the safety valves, since reliability of these type valves to completely close after steam relief is somewhat less than that observed for the steam generator power operated relief valves. In addition, only the relief valves have backup isolation valves which could be used to terminate steam flow if necessary. Therefore, it was concluded that the relief valve setpoint should not be adjusted for this event.

5. Subsequent recovery of the DOEL 2 plant included drain of the affected steam generator using a nitrogen blanket. The ability to drain the steam generator in the manner described in the DOEL report is somewhat plant dependent, although such a procedure could probably be accomplished with any design. However, such a procedure lies beyond the scope of the recently revised Westinghouse Emergency Operating Instructions, which provide guidance to establish a safe, stable condition after the transient. Draining of the contaminated water in the affected steam generator requires consideration of cleanup capability and holdup tankage, and is not related to establish a safe system configuration with respect to either core cooling or the potential for radiation releases outside containment. The procedure followed at DOEL 2 was reasonable and effective, and should be conveyed to other operating utilities.

6. A review of the equipment performance during the shutdown sequence indicated an area that required further investigation. During recovery procedures from the incident, the subsequent blocking of the safety injection signal was permitted by the S.I. block on low pressurizer pressure by means of the P11 permissive, but could not be satisfactorily accomplished by the system level reset and block S.I. push button. This system level reset push button was manually actuated several times and, following each manual actuation, the safety injection signal was reinitiated until it was finally blocked by manual actuation of another reset/block push button permitted by P11. The safety injection signal is also derived from process parameters other than low pressurizer pressure. Although these process parameters did not call for a safety injection, had they done so, the recovery may not have gone as smoothly

as it apparently did. The logic is designed such that the S.I. signal can be reset and blocked even if the initiating condition is still present and, due to a relay sequence timing condition from the switching time of a relay, this part of the sequence did not work as designed. This problem was not found during testing due to the test procedures masking this specific relay sequencing timing condition. If the relay timing sequence had been as designed, the S.I. interruption could have been accomplished about 10-15 minutes sooner.

7. Containment isolation Phase A resulted in loss of air supplies to some essential equipment of the component cooling water system, with a potential impact on RCP operation resulting from loss of cooling to the thermal barrier. Current interface criteria assure that component cooling water to the reactor coolant pump motor bearings is available in the presence of a containment isolation Phase A condition. Further, RCP design is such that either seal injection flow or CCW flow to the RCP seals is sufficient to provide pump seal integrity. Therfore, current Westinghouse design philosophy permits one or the other to be available, even during the consequences of a containment Phase A isolation.

8. All other equipment performed as expected and within their specified time frames. Safety injection pumps started and performed as expected, containment isolation on Phase A signal due to S.I. was accomplished as expected. No instrumentation malfunctions were identified. The blow-down radiation monitoring system was used to determine the steam generator that was leaking.

III. Impact

The specific incident of steam generator tube rupture is applicable to all pressurized water reactors. The recovery sequence as experienced at DOEL 2, specifically the difficulty in blocking and resetting safety injection, could be a potential problem for PWR's that have relay systems for safeguards actuation.

A review of Westinghouse logic and hardware control systems shows that the plants can be divided into two general categories:

1. Those that contain the Solid State Protection System (SSPS).

2. Plants that process safeguards actuation signals through relay systems, i.e., relay plants.

Concerning the SSPS plants, even though the reset and block of S.I. is functionally similar to relay plants, the translation of these functions into hardware design is sufficiently different that the same sort of relay timing problem that DOEL 2 had could not occur. Furthermore, the periodic testing of the logic by means of the semi-automatic tester and the safeguards test cabinets is more comprehensive. In addition, that part of the S.I. block/reset circuit that was not designed to be on-line testable was covered by a Technical Bulletin NSD-TB-11. Therefore, the only plants which need to be considered are Relay Plants. These plants functionally also have an S.I. reset and block similar to DOEL 2. On plants where S.I. reset/block is not permitted following a reactor trip, they functionally are the same. Also, in the translation of these functions into hardware design, the circuits are very similar. The early Westinghouse relay plants are H. B. Robinson #2, Zion #1, Zion #2, Conn Yankee/Haddam Neck, Turkey Point #3, Turkey Point #4, Indian Point #2, Indian Point #3, Prairie Island #2, Prairie Island #1, Robert E. Ginna, San Onofre #1, Surry #1, Surry #2, Point Beach #1, Point Beach #2, Kewaunee, Yankee-Rowe, Belgium #3, Mihama #1, Ko-Ri #1, Takahama #1, Beznau #1, Beznau #2, Jose Cabrera Zorita, and Ardennes.

The desired sequence of operation of the relays and reset push button for DOEL 2 has been compared with the desired sequence for a design typical of the early Westinghouse domestic relay plants. The evaluation of this comparison yields:

1. The evaluation of DOEL 2 showed that the Time Delay Relay (TDR) opened its normally open contact before the Seal-in Relay had time to close its normally open contact. This did not allow the Seal-in Relay to

block the S.I. signal. The TDR was several milliseconds short of allowing the seal-in relay to block the S.I. signal. This information was obtained from testing done at DOEL 2 after the event.

2. Based on the evaluation of early Westinghouse relay plants, the time delay relay will open its normally open contact nine milliseconds after the reset seal-in relay closes its normally open contact, thus achieving its goal by a nine millisecond overlap. This is based on the technical bulletin data.

This evaluation shows that there are not equivalent generic implications on Westinghouse plant designs based on the design and technical data available on the component involved. Further evidence of this is the numerous inadvertent safety injection incidents in Westinghouse plants. These incidents, to the best of our knowledge, have been successfully terminated without any reported difficulties of not being able to block S.I. by the system S.I. block even when the S.I. signal was still present. For example, 14 inadvertent S.I. events occurred in 1975 which were terminated in 10 minutes. One event in 1975 was terminated in 30 minutes because of loss of indication. There also were nine events in 1975 whose termination times were not reported.

IV. Recommendations

The Westinghouse Nuclear Technology Division's review of available information on the steam generator tube leak incident at DOEL 2 has not resulted in any actions to modify the Westinghouse Emergency Operating Instructions, operating procedures or equipment. The recovery actions at DOEL 2 were adequate to protect the plant and the health and safety of the public. These conclusions are based upon NTD review considering typical Westinghouse supplied equipment, the revised Emergency Operating Instructions and Westinghouse Standard Technical Specifications. Operating utilities should consider specific plant technical specifications, testing procedures, and design modifications that may have been implemented in performing their review of the transient.

It is recommended that the Westinghouse relay plants be informed as to the incident at DOEL 2 and the Westinghouse review of the incident, for information.

In the same context of information, the NRC should be informed of the incident and the Westinghouse evaluation of it.

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WESTINGHOUSE EVALUATION OF LICENSEE INCIDENT

Operating Plant - North Anna Unit 1
Operating Utility - VEPCO
Date of Incident - September 25, 1979

INTRODUCTION

The North Anna Unit 1 plant is located in Virginia and began commercial operation June 6, 1978. It is a three-loop 2775 MWt PWR of Westinghouse Design. The event of interest is a turbine trip followed by a stuck-open steam dump valve which caused safety injection initiation.

I. DESCRIPTION OF INCIDENT

The description of the incident is taken from interviews with VEPCO operating personnel and management, from review of plant records, and from the VEPCO Licensee Event Report, No. LER 79-128/01T-0, a copy of which is Appendix A of this report.

A. Plant Operating Conditions

The plant was operating at 78% power in order to extend the life of the first core loading. Core average burnup was approaching 15,900 MWD/MTU. Boron concentration was 4 ppm, and one charging pump was operating under normal pressurizer level control to balance the maximum letdown capacity of 125 GPM. Pressurizer heaters were manually set at full power to force pressurizer spray under automatic pressure control, in order to keep the pressurizer boron concentration in equilibrium with the reactor coolant system.

The reactor coolant average temperature was about 3°F below normal at 78% power. Pressurizer and steam generator water levels were normal. Two of the three main feedwater pumps were operating. The block valve on one of the two pressurizer power-operated relief valves was closed to prevent leakage.

B. Sequence of Events

The following description is summarized, along with the timing and the source of the timing information, in Appendix B. Copies of control room recorder charts are shown in Appendix C, followed by some plots made from plant computer printouts.

1. Initiating Sequence

At 0544 on 9/25/79 a low pressure feedwater heater drain cooler dump valve began to cycle. This cycling was believed to be due to tube leakage inside the drain cooler. Subsequent examination has shown that a total of twelve tubes in

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the drain cooler were leaking. The leakage exceeded the capability of the drain valves, causing the extraction steam condensate level to rise into the heater to the turbine trip setpoint.

At 46 seconds past 0609 turbine trip occurred. Turbine trip immediately caused a reactor trip, and also tripped open the eight condenser steam dump valves to the full-open position. As the valves modulated closed the first time, an operator noted from the valve position indicators that one valve had stuck in the full-open position. A man went immediately to see whether any manual action could be taken to close that valve. When it was found that the valve could not be closed, closing of the non-return valves in the main steam lines (a 3 minute process) was started. (The steamline isolation valves were manually tripped at 0616.)

Later disassembly and evaluation of the stuck steam dump valve showed that the valve had overtravelled when it opened. Instead of stroking the design stroke of 2-3/4 inches, the valve had stroked 3-1/8 inches. The overtravel caused the valve plug to wedge into a 15 degree taper at the top of the valve balancing cylinder. The wedging force was greater than the valve operator closing spring force so the valve remained open after it was signaled to close. In addition, when the valve overtravelled and wedged open, the maximum specified allowable flowrate through the valve could have been exceeded. Instead of limiting flow to 1.02×10^6 lb/hr. steam at 1100 psia inlet pressure, the valve would have permitted a flowrate of 1.29×10^6 lb/hr. at 1100 psia while it was open.

Meanwhile, steam generator water levels fell as a normal result of the turbine trip, and the low-low level setpoint was reached and all three auxiliary feedwater pumps were automatically started between 8 and 12 seconds after turbine trip. About 1 minute later, one main feedwater pump was manually turned off, and the main feed control valves were closed automatically by the combination of low RCS temperature and reactor trip. (The other main feed pump was tripped by SI initiation 5 minutes after turbine trip.)

2. Initiation of Safety Injection

The steam dump control system closed the seven controllable dump valves for the last time less than a minute after turbine trip. Continued cooling of the primary system by steam flow through the stuck valve and by auxiliary feedwater caused a continued lowering of the pressurizer water level and pressure. Low pressurizer level caused automatic

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letdown isolation within two minutes. Low pressurizer pressure initiated safety injection five minutes after turbine trip, at 0614:45. The resulting start of a second charging pump and redirection of flow through the safety injection path immediately started raising pressurizer water level and pressure. (Subsequent calculations indicated that although the water level dropped below the bottom tap of the level indicator, the pressurizer and surge line did not empty.)

Between one and two minutes after safety injection initiation the main steamline isolation valves were manually tripped closed, terminating the steam flow through the stuck dump valve. All reactor coolant pumps were manually tripped, as is required by North Anna procedures following safety injection on low pressure.

3. Control of Primary and Secondary Systems

At 0619, four minutes after initiation of safety injection, the pressurizer level and pressure had returned approximately to their normal values and one of the two high-head charging pumps was turned off. After another minute the pressurizer power-operated relief valves started cycling to hold the pressure near 2335 psig.

A check was made of reactor coolant pump conditions with the thought of starting them to restore pressurizer spray, to achieve uniform mixing in the primary system, and to stabilize primary system conditions. Pumps A and C had lost their seal leakoff indications following the SI signal, preventing them from being started. RC pump B, which is not on a loop with the pressurizer surge line or a spray line, was started at 0629 to achieve coolant mixing.

Letdown was initiated at 0627; however the flowrate cannot be determined since the orifice alignment and the effects of possible flashing (without charging through the regenerative heat exchanger) are unknown. By 0635 the charging system had been realigned to charge through the normal path instead of through the Boron Injection Tank. Charging flow was throttled to about 20 GPM, the auxiliary spray valve was opened, and letdown increased to the maximum. At 0637, the PORV stopped cycling, and pressurizer pressure and water level started to decrease. The peak indicated water level reached was about 73% of span, and the total mass of steam released through the PORV was later calculated to be less than 3500 lb.

Auxiliary feedwater pumps had brought the steam generator water levels well up into the narrow range span by 0625. At that time one main feed pump was restarted and the auxiliary

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pumps were secured. Feed flows were held to a low rate until 0631, when they were increased to bring indicated levels up to normal at about 0636. Then flows were throttled down, and again throttled to no flow at 0647 to 0650. Cold leg temperature reached a minimum of 473°F at 0627, following termination of auxiliary feed flow. After the RCP was started at 0629 and main feed was throttled at 0636, reactor coolant and secondary side temperatures were slowly increased by decay heat until they reached normal two hours after turbine trip.

At 0646, about 36 minutes after turbine trip, volume control tank high level and high pressure alarms were actuated, for reasons discussed in the next section. As a result, letdown flow was first reduced, and then temporarily stopped at 0659. Pressurizer water level and pressure increased and the PORV again was cycled from about 0701 until letdown was restored at 0705. Pressure continued to be sensitive to level changes until about 0820, when the pressurizer heaters finally brought the water in the pressurizer up to saturation temperature.

Before about 0820, operators noted poor pressure control, similar to what would be expected with noncondensible gas in the pressurizer. After that time the pressure was held near normal while the pressurizer water level was gradually reduced to normal over the next hour. Subsequent analysis of a pressurizer steam space sample did not show unusual gas concentration, and the poor pressure control is attributed to lack of normal spray and pressurizer water subcooling.

During the cooldown transient the hot leg temperature went from an initial 590°F to a minimum indicated value of 482°F in 22 minutes. As a result of the primary system cooldown (greater than 100°F/hr normal cooldown rate) Westinghouse was requested to evaluate the effect of the cooldown on reactor vessel integrity. The cooldown was determined not to have any adverse impact on this reactor vessel.

4. Volume Control Tank Overflow

When normal letdown was established, the operating charging pump was not aligned to take suction from the VCT and was instead still aligned to the RWST. As a result, the VCT level increased so that the VCT level control valve began diverting water to the Boron Recovery System (BRS) via the gas stripper. An upset in the gas stripper resulted in the closing of the inlet trip valve to the stripper due to high stripper level.

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With the VCT level control valve fully diverted to the BRS, the closing of the stripper trip valve blocked letdown. This caused the lower pressure letdown relief valve to lift (setpoint 200 psig) discharging water directly to the VCT. At 0646, about 36 minutes after the turbine trip, the VCT high pressure and level alarms were actuated and shortly afterwards the relief valve lifted (setpoint 75 psig). This relief valve discharged to the High Level Liquid Waste Tank (HLLWT); initially a mixture of H_2 and radioactive gases were discharged, followed by water as the VCT became water solid.

The HLLWT has a vent to the plant process vent which would have released the noble gases to the environment through a charcoal filter. However, the HLLWT vent line had a disconnected flange which allowed the radioactive gases to leak into the auxiliary building. The noble gases were ultimately discharged to the environment via the plant charcoal and HEPA filters and the plant vent so that offsite doses were similar to those which would have resulted from a normal HLLWT vent line configuration.

Even if the HLLWT vent had been connected, some gases might have escaped into the auxiliary building. The input from the VCT relief valve could cause the HLLWT pressure to rise slightly because of the limited vent capacity, causing radioactive gases to be vented to the Low Level Liquid Waste Tanks out into the auxiliary building through its overflow line.

The airborne activity levels in the auxiliary building during the first three hours following the plant trip were up to 156 times MPC. As a result access to these areas was restricted. Had a worker been exposed to these activity levels for the full 3 hours the dose would have been significantly less than the quarterly limit. After the first 3 hours restricted access was not necessary as the airborne activity was below MPC. See VEPCO LER (Appendix A of this report) for additional information on the auxiliary building radiation levels.

5. Reactor Coolant Pump Seal Leakage

The indicated seal leakoff from Reactor Coolant Pumps A and C dropped to zero sometime following the plant trip. Based on subsequent inspection of the seals in pump C the following sequence has been derived.

The seal leakoff was normal prior to the plant trip although that from pump C was low. The SI signal generated a containment isolation signal which isolated the seal leakoff

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line at the containment. This did not block the seal leak-off path because of a relief valve (setpoint 150 psig) located inside the containment. Inspection of the No. 1 seal indicated that it was leaking at its normal rate. However, the No. 2 seal was found to be worn, which together with the increased backpressure, indicates that the No. 1 seal leakage was probably redirected through the No. 2 seal. This increased No. 2 seal leakage may have increased the leakage through the No. 3 seal and contributed to a Hi-Hi air particulate alarm in the containment.

C. Environmental Impact

VEPCO has determined that there was a noble gas release from the auxiliary building at less than 0.05 percent of the release rate limit allowed by the Technical Specifications. No radiation exposures above background were observed in the 14 downwind TLD's on the perimeter fence.

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II. Evaluation of Sensitivities

This section presents a general discussion of the transient in comparison with FSAR analysis of a similar event, and also discusses briefly the effects of possible alternative operating procedures.

Accidental depressurization of the main steam system is classified in the FSAR as a Condition II fault, that is, a fault of moderate frequency. The specific challenge presented by such an event is whether the reactor would, because of the associated primary system cooldown, go critical and experience DNB and possible fuel damage. The case which bounds the consequences of such an event is the spurious opening of a steam dump valve. The nature of the September 25 event was much less severe than the transient shown in the FSAR, since the FSAR analysis includes highly conservative assumptions which were not present in the September 25 event. Significant differences include the following:

1. Initial T_{AVG} = 570°F, vs. hot no-load condition. This provided additional stored energy, most of which was dissipated by the controlled steam dump operation which brought T_{AVG} to the no-load value.

2. Initial power = 78%, vs. no-load in the FSAR. Thus decay heat was available to reduce the cooldown rate and heat the plant after cooldown was terminated.

3. Automatic feedline isolation, not assumed in the FSAR. This tended to make the rate of cooldown less rapid than in the FSAR.

4. Manual main steamline isolation, not assumed in the FSAR. This ended the plant cooldown.

5. Two high-head charging pumps on SI, vs. one (worst single failure assumption) in the FSAR. This, together with the termination of the cooldown and decay heat, induced a rapid repressurization, as opposed to the extended decrease in pressure shown in the FSAR.

In both cases safety injection was initiated when the cooldown had adequately reduced pressurizer pressure, and was sufficient to prevent the reactor from returning to a critical condition. Therefore, in both the FSAR case and the actual incident, DNB was precluded.

Emergency operating instructions in effect at the time of the event required the operators to trip off all reactor coolant pumps immediately following safety injection initiation due to low pressurizer pressure. If, instead, the procedure called for tripping the pumps only after a lower reactor coolant pressure had been

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reached, the RCP's would have been left running. The principle effect of this difference would have been that pressurizer spray would have been available under automatic control throughout the transient. The spray capacity would be more than adequate to prevent the pressure from rising to the pressurizer power-operated relief valve control setpoint, and thus, PORV's would not have opened at all. Following termination of safety injection, pressure control below the PORV setpoint pressure would be by charging and spray, rather than by charging, auxiliary spray, and letdown. Thus, the necessity for the operator to letdown either to reduce pressure or to provide tempering of auxiliary spray would not be present; letdown could be controlled as required for pressurizer level control and as dictated by conditions in the volume control system.

Another area under current discussion is the appropriate criteria for termination of safety injection flow. The procedures in effect required SI to be terminated no sooner than 20 minutes after initiation unless overpressurization (pressure approaching the safety valve setpoint of 2485 psig) was imminent. An alternate procedure which has been proposed would, in this case, permit SI termination when the indicated RCS pressure goes above 2000 psi, the steam generator water levels show that the U-tubes in at least one steam generator are clearly covered, and the indicated pressurizer water level is above 50%. In this event the RCS pressure reached 2000 psi about three minutes after SI actuation; the narrow-range steam generator level signals gave unambiguous non-zero indications eight minutes after the PORV's started cycling; and the pressurizer level reached 50% fourteen minutes after SI actuation and eight minutes after PORV cycling started. Again, with reactor coolant pumps operating, pressurizer spray would prevent PORV opening.

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III. RECOMMENDATIONS

A. Steam Dump Valve Failure

The incident of a valve overtravelling and wedging open has the potential to occur in all plants which have the Copes Vulcan Valve, Model D-100, with second generation tandem trim. All plants for which this valve has been supplied by Westinghouse will be notified and instructed how to adjust the valves to prevent such an occurrence.

B. RCP and SI Termination Procedures

Westinghouse recommendations concerning instructions for terminating reactor coolant pump and safety injection operation following events which actuate safety injection have previously been discussed with the Westinghouse Owners Group. These recommendations are being reviewed to determine whether any changes should be made. These procedures are also presently being discussed with the NRC.

C. Spray With One RCP

Current Westinghouse reference operating instructions state that with only one RCP operating spray is available only when that RCP is on the loop having the pressurizer surge line. This is because the static pressure in the active-loop hot leg is lower than in the inactive hot legs, mainly due to the high velocity head in that loop. It is recommended that plant operating instructions consider this situation.

D. Auxiliary Spray/Subcooled Pressure Control

Operating procedures should recognize the differences in pressurizer operating characteristics when pressurizer water is subcooled. For rapid pressure reductions during normal operation, flashing of saturated pressurizer liquid is the dominant mechanism slowing the rate of pressure decrease. For longer-term recovery (over tens of minutes), pressure is restored by boiling saturated liquid with pressurizer heaters. If the pressurizer liquid is subcooled, neither of these mechanisms exists, pressure drops rapidly as pressurizer water level decreases, expanding the steam bubble. Therefore, under these conditions, maximum pressurizer heaters should be energized, and pressurizer liquid temperature monitored, until saturated conditions are restored.

Similarly, pressurizer spray normally controls pressure increases. Without spray, an increase in pressurizer level compresses the steam bubble into the superheat range with a

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relatively large pressure increase. The pressure characteristic is similar to compressing a non-condensible gas. Auxiliary spray may be used to mitigate pressure increases, but will not be as effective as the much higher flow rate obtainable with normal pressurizer spray.

The preferred mode of auxiliary spray operation is to use letdown flow in order to minimize thermal shocks. To achieve sufficient spray flow the charging line isolation valve to the cold leg should be closed, the auxiliary spray valve opened, and the charging line flow control valve used as necessary to control spray.

E. Letdown Initiation After SI Actuation

Each utility should review its policy and procedures for resetting containment isolation, and restoring normal letdown, following an automatic containment isolation signal. In particular, are existing radiation monitoring or sampling practices believed adequate to preclude significant contamination of auxiliary systems or atmospheric release in the event that reactor coolant activity increased significantly during whatever transient actuated containment isolation? (Note: According to NUREG-0600, the principal pathway for radioactive release to the environment from the TMI-2 accident was "through the makeup and purification system".)

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APPENDIX A

October 9, 1979

Mr. James P. O'Reilly, Director
Office of Inspection and Enforcement
U. S. Nuclear Regulatory Commission
Region II
101 Marietta Street, Suite 3100
Atlanta, Georgia 30303

Serial No. 829
PO/[illegible]:baw
Docket No. 50-338

License No. NPF-4

Dear Mr. O'Reilly:

Pursuant to North Anna Power Station Technical Specifications, the Virginia Electric and Power Company hereby submits the following Licensee Event Report for North Anna Unit No. 1.

Report No.	Applicable Technical Specifications
LER 79-123/01T-0	T. S. 6.9.1.8.1.

This report has been reviewed by the Station Nuclear Safety and Operating Committee and will be placed on the agenda for the next meeting of the System Nuclear Safety and Operating Committee.

Very truly yours,

C. M. Stallings
Vice President-Power Supply
and Production Operations

Enclosures (3 copies)

cc: Mr. Victor Stello, Director (40 copies)
Office of Inspection and Enforcement

Mr. William G. McDonald, Director (3 copies)
Office of Management Information and
Program Control

bc:
Mr. W. L. Proffitt
Mr. B. R. Sylvia
Mr. E. A. Baum
Mr. G. A. Olson-EEI
Mr. M. W. Stubbs
Mr. M. S. Kidd-NRC/N. Anna
Mr. C. M. Stallings
Mr. J. A. Ahladas
Mr. J. L. Perkins
Mr. R. M. Taylor
Mr. D. W. Speidell, Jr.
Mr. W. C. Daley
Mr. W. L. Stewart
Mr. P. R. Beament (8)
Mr. A. L. Hogg-N. Anna
Mr. W. R. Cartwright (2)

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NRC FORM 366
(7-77)

U. S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT

CONTROL BLOCK: | | | | | | | ① (PLEASE PRINT OR TYPE ALL REQUIRED INFORMATION)

0 1	V A N A S 1 ②	0 0 - 0 0 0 0 0 - 0 0 ③	4 1 1 1 1 ④	⑤
	LICENSEE CODE	LICENSE NUMBER	LICENSE TYPE	CAT

CON'T

0 1	REPORT SOURCE: L ⑥	0 5 0 0 0 3 3 8 ⑦	0 9 2 5 7 9 ⑧	1 0 0 9 7 9 ⑨
		DOCKET NUMBER	EVENT DATE	REPORT DATE

EVENT DESCRIPTION AND PROBABLE CONSEQUENCES ⑩

0 2 At 0614 a Safety Injection occurred due to a low pressurizer level coincident

0 3 with low pressurizer pressure. This event is a 24 hour reportable occurrence as per

0 4 req. guide 1.16 and as per T.S. 6.9.1.8.i. Following the event a radiation release

0 5 occurred which was less than 0.05% of the instantaneous release rate per E.T.S.

0 6 2.2.3.a. Boundary radiation detectors showed only background radioactivity and

0 7 therefore at no time was the health and safety of the general public affected.

0 8

0 9	SYSTEM CODE	CAUSE CODE	CAUSE SUBCODE	COMPONENT CODE	COMP. SUBCODE	VALVE SUBCODE
	S F ⑪	E ⑫	B ⑬	V A L T E X ⑭	H ⑮	B ⑯

⑰ LER/RO REPORT NUMBER	EVENT YEAR		SEQUENTIAL REPORT NO.		OCCURRENCE CODE	REPORT TYPE		REVISION NO.
	7 9	—	1 2 8	/	0 1	T	—	0

ACTION TAKEN	FUTURE ACTION	EFFECT ON PLANT	SHUTDOWN METHOD	HOURS ㉒	ATTACHMENT SUBMITTED	NPRD-4 FORM SUB.	PRIME COMP. SUPPLIER	COMPONENT MANUFACTURER
X ⑱	X ⑲	A ⑳	C ㉑	0 0 0 0	Y ㉓	N ㉔	A ㉕	C 6 3 5 ㉖

CAUSE DESCRIPTION AND CORRECTIVE ACTIONS ㉗

1 0 The cause of the SI was steam dump valve TCV-1408G stuck open following a reactor

1 1 trip, which depressurized the reactor coolant system. Corrective actions were to

1 2 return the plant to stable conditions by the control room operators and later

1 3 initiate a plant cooldown to the cold shutdown mode of operation.

1 4

1 5	FACILITY STATUS	% POWER	OTHER STATUS ㉚	METHOD OF DISCOVERY	DISCOVERY DESCRIPTION ㉜
	X ㉘	0 7 8 ㉙	Coastdown	A ㉛	Automatic Actuation

1 6	ACTIVITY RELEASED	CONTENT OF RELEASE	AMOUNT OF ACTIVITY ㉟	LOCATION OF RELEASE ㊱
	G ㉝	N ㉞	7.5 Curies Total	Ventilation and Process Vents to Atm.

PERSONNEL EXPOSURES

1 7	NUMBER	TYPE	DESCRIPTION ㊴
	0 0 0 ㊲	Z ㊳	NA

PERSONNEL INJURIES

1 8	NUMBER	DESCRIPTION ㊶
	0 0 0 ㊵	NA

LOSS OF OR DAMAGE TO FACILITY ㊸

1 9	TYPE	DESCRIPTION
	Z ㊷	NA

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PUBLICITY

2 0	ISSUED	DESCRIPTION ㊺	NRC USE ONLY
	Y ㊹	Public News Release	

NAME OF PREPARER W. R. Cartwright PHONE: [illegible]

Description of Event:

At 0544 on 9/25/79 with reactor power at 78%, the fifth point heater drain cooler dump valve LCV-SD-182B began to cycle. This cycling was believed to be due to a tube rupture inside the 5B drain cooler. The leakage was more than the capability of the drain valves causing extraction steam condensate to back up into the 5th point heater to the turbine trip setpoint.

At 0609, a turbine trip occurred and resulted in a reactor trip. At this time the main steam dump valves opened to reduce RCS temperature to 547°F. When the RCS temperature decreased below the steam dump setpoint, steam dump valve TCV-140BG failed to close. The steam dump valve was then isolated by closing the main steam trip valves.

Excessive cooldown caused by the open steam dump valve resulted in an RCS depressurization and a resultant Pressurizer Lo Pressure signal. This signal, combined wit the administratively tripped Pressurizer Lo Level signal, initiated a safety injection of the Emergency Core Cooling System. This event occurred at 0614.

The RCP's were immediately manually tripped as required. As a result of the safety injection and the termination of the cooldown, the RCS pressure began to increase. One of two SI charging pumps was secured at 0619. At 0620, the pressurizer pow r operated relief valve began to cycle and maintained pressure at 2335 psig until normal letdown and charging were established.

When normal letdown was established, the remaining charging pump was still drawing suction from the RWST. This resulted in an increasing level within the Volume Control Tank (VCT) such that the VCT level control valve (LCV-1115A) began to modulate to divert reactor coolant letdown to the Boron Recovery System via the gas stripper. The high flow to the stripper resulted in the inlet trip valve to the stripper closing due to high stripper level. At this time, LCV-1115A was fully diverted to the gas stripper; however, the inlet control valve to the stripper (TV-BR111A) was closed. The pressure in the letdown line increased to the low pressure letdown line relief valve (RV-1209) (setpoint of 200 psig. This valve discharged directly to the VCT. The VCT pressure increased to the VCT relief valve (RV-1257) setpoint of 75 psig. This valve discharged letdown water and gases directly to the High Level Liquid Waste Tank (HLLWT). The normal action at this point would be the release of noble gases from the HLLWT through a vent line and through the plant process vents. In a point in the vent line a flange had been disconnected and the noble gases were released into the auxiliary building. The gases were then vented through the plant charcoal and HEPA filters and out of the plant ventilation vents.

Had the flange not been disconnected, a release of noble gases to the auxiliary building may have occurred. The discharge rate of VCT reactor coolant to the HLLWT may have been too much to pass through the normal vent line, therefore the reactor coolant gases would have vented to the Low Level Liquid Waste Tanks and out into the auxiliary building via the Low Level Liquid Waste Tank overflow line.

The following is submitted as additional information. The release was well within the Environmental Technical Specifications limit.

AUXILIARY BUILDING AIRBORNE ACTIVITIES
09/25/79

TIME	ELEVATION	EXPLANATION
0700	274'	100.96* Times MPC. Principle Nuclei involved were Xe 133 & 135 with some Kr 85 and Rb 88.
	259'	155.68* Times MPC. Principle Nuclei involved were Xe 133 & 135 with some Kr 85 and Rb 88.
0800	274'	1.12* Times MPC. Principle Nuclei involved were Xe 133 & 135 with traces of Rb 88.
0900	259'	6.01* Times MPC. Principle Nuclei involved were Xe 133 & 135 with traces of Rb 88.
1000	259'	0.68* Times MPC. Principle Nuclei involved were Xe 133 & 135 with traces of Rb 88.
1030	259'	Less than 0.1 times MPC. Principle Nuclei involved was Rb 88. All readings after 1030 were less than 0.1 times MPC.

*This value represents the total submersion hazard involved with the total of all Nuclei.

Perimeter TLD's were pulled and evaluated. No radiation exposures above background were observed in the 14 TLD's in the downwind direction on the perimeter fence.

Total Noble gas releases from ventilation vents A and B and the process vent amounted to 4.7E-02% of the release rate limit of noble gases.

During this event, several other events occurred which are contrary to Technical Specifications.

After the turbine trip, a turbine reheat valve failed to close which is contrary to T.S. 3.7.1.8. The action statement was entered and the turbine was isolated from the main steam supply.

When the main steam dump valve failed to close, an RCS cooldown of 110°F in 30 minutes occurred. This event is contrary to T.S. 3.4.9.1.b. The RCS temperature was restored to within the T.S. limits by closing the main steam trip valves.

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Upon receiving the SI signal, the control room bottled air system failed to initiate as required by T.S. 3.7.7.1. The Action Statement requirements were met by cooling down to the cold shutdown mode.

As a result of the safety injection, the Boron Injection Tank was left containing 2000 ppm borated water instead of 20,000 ppm borated water as required by T. S. 3.5.4.1 and the Emergency Condensate Tank was depleted less than 110,000 gallons by the Auxiliary Feedwater Pumps which is contrary to T.S. 3.7.1.3.

The appropriate Action Statements of these events were entered.

Although not reportable, a Hi Hi air particulate alarm in the Containment occurred. This is believed to be due to leakage by the #3 seals from the secured RCP's.

The ECCS actuation is reportable as per T.S. 3.5.2 which requires a 90 day report, Reg. Guide 1.16 requires a 24 hour notice and written follow up as per T.S. 6.9.1.8.f. This is the third ECCS actuation reportable as per T.S. 6.9.1.b.

This event is generic to Unit #2 since it uses the same type of steam dump valves.

Probable Consequences of Occurrences:

The purpose of the Emergency Core Cooling System is to ensure adequate cooling of the reactor in the event of a loss of coolant accident.

Since the ECCS actuated as required and at no time was the reactor in danger of being undercooled, the safe operation of the plant was not affected.

Also, since the radiation release was well within the limits of the Technical Specifications at no time was the health and safety of the general public affected.

Cause of Occurrence:

The cause of the intial reactor trip was a turbine trip due to a Hi Level in the 5B feedwater heater.

The resulting RCS cooldown of 110°F and depressurization was due to a steam dump valve failing to close. The reason for the valve failure is currently being investigated by Vepco, Westinghouse and Copes-Vulcan.

The cause of the Reheat Stop valve failing to close is unknown at this time and will be investigated by Vepco and Westinghouse during a turbine inspection.

The low level of the ECST and the underboration of the BIT are results of the safety injection. The safety injection pumps draw suction from the RWST and pump through the BIT leaving 2000 ppm borated water in the BIT. The ECST level was lowered by the Auxiliary feedwater pumps feeding water to the steam generators.

The failure of the control room bottled air system was the result of an apparent pressure shock to the Bourdon tubes in the discharge of pressure controller of the system. This pressure shock deformed the tubes leaving them inoperable.

The release of radioactive noble gases was due to the automatic shutdown of the gas stripper and the continued letdown of the reactor coolant while the VCT was not supplying makeup to the reactor coolant system. The overfilling of the VCT occurred during the time operations personnel were regaining RCS pressure control while still maintaining the required high head safety injection flow to the RCS. The transition from the safety injection mode to the normal charging mode of operation was made in a slow and cautious manner so as not to overpressurize the RCS. This evolution resulted in overfilling the VCT and the resultant release of radioactive gases.

Immediate Corrective Actions:

Upon actuation of the automatic reactor trip, the operators performed the required immediate corrective actions of the emergency procedures. After the main steam dump valve failed in the open position, the operators attempted to isolate the valve by manually closing a steam dump isolation valve. It was determined that closing the large valve would consume too much time, therefore, the dump valve was isolated by closing the main steam trip valves.

After the automatic initiation of safety injection from low RCS pressure, the operators manually tripped the RCP's as required by procedures and began monitoring RCS parameters to ensure adequate core cooling.

At approximately 0619 the operators secured one of two High Head Safety injection pumps and at approximately 0627 began to establish normal letdown. After 20 minutes of cold leg injection, at approximately 0633, safety injection was secured. At this time a RCP and a feedwater pump were in operation and the plant was determined to be stable.

When a high level and pressure were noted in the VCT, operations personnel re-established the RCS letdown to the Boron Recovery System via the gas stripper. This alleviated the high pressure and level condition in the VCT and the relief valve closed ending the release of reactor coolant to the liquid waste tank. The disconnected flange in the HLLWT vent line was reconnected.

The operators refilled the ECST as required by the appropriate action statements and began to cooldown the plant to the cold shutdown mode by following normal procedures.

Following the 110°F cooldown of the RCS, Westinghouse was notified and they determined that there was no effect on the RCS fracture toughness properties.

Scheduled Corrective Actions:

During the current refueling outage, investigations into the failure of the main steam dump valve and the turbine reheat stop valve will be conducted by Vepco, Westinghouse and Copes Vulcan.

An engineering review of the letdown divert to the boron recovery system will be performed to determine if any improvements may be implemented to the present system.

A design change will be incorporated into the control room bottled air system which will provide protection to the Bourdon tubes from over-pressurization.

A continued investigation into the effect of the transient on the plant is being performed by Vepco and Westinghouse.

Also, Vepco and Westinghouse are reviewing the problem of #2 seal leakoff from secured RCP's.

Actions Taken to Prevent Recurrence:

Corrective actions to the main steam dump valves and reheat stop valves will be performed when the results of the investigations are available.

An engineering review into the problem of high flow in the High Level Liquid Waste Tank vent line will be undertaken.

Any lessons learned from Vepco and Westinghouse reviews of the transient will be incorporated into Vepco procedures and will be forwarded to the Westinghouse Owners Group.

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APPENDIX B

SEQUENCE OF EVENTS SUMMARY

Table B lists significant events in sequence, and the sources for the timing listed. The time base is that indicated by the plant computer (Westinghouse P-250) printout. Clock times listed by the alarm typewriter (time source 4) are rounded down to the next lowest even minute.

The timing sources are as follows:

1. P-250 Sequence of Events Record
2. P-250 Post-Trip Review
3. P-250 Post-Accident Analysis Log
4. Alarm Typewriter
5. Control room recorder charts (time scale 1 in./hr)
6. Operator interviews, 9/27/79
7. Discussions with operating staff, 9/28/79

TABLE B

SEQUENCE OF EVENTS SUMMARY

Clock Time	Minutes After Turbine Trip	Event	Timing Source
0545	-25	LP FW heater drain dump valve alarm	4
0609:46	0:0	Turbine trip on high FW heater drain level Reactor trip on turbine trip Steam dump valves trip open One dump valve stuck open	1 1 6 6
0609:54	0:08	All three auxiliary FW pumps start on S/G lo-lo level within 3 seconds.	1, 4
0611	1	One main feedwater pump tripped manually	4
0611:10	1:24	Main feedwater flow goes to zero	2
0611:30	1:44	Letdown isolation on low pressurizer pressure	1,4
0612	2	Volume Control Tank low level alarm	4
0614:45	4:59	Safety injection on low pressurizer pressure	1,4
0615	5	Second main feedwater pump tripped from SI	4
0616	6	Main steam stop-check valves tripped closed manually	5,4
0616	6	All reactor coolant pumps turned off manually	4
0617	7	Pressurizer level returned to 9%	4
0618	8	Pressurizer pressure 2160 psig	4
0619	9	One charging pump stopped manually	4
0620:30	10:45	Pressurizer PORV starts cycling open	3
0625	15	One main feed pump started, auxiliary feed stopped	3,7
0627	17	Letdown initiated	4
0629	19	Reactor coolant pump B started	4,3

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TABLE B (Continued)

0634	24	First S/G level returns above normal	3
0635	25	Charging flow realigned to normal	4
0637	27	Pressurizer PORV stops cycling	3
0646	36	VCT high level alarm	4
0646	36	VCT high pressure alarm	4
0701	51	Pressurizer PORV opens, cycles about 4 minutes	5
0704	55	Bank of dump valves isolated, start opening main steam valves bypass (next 40 minutes)	5,6
0716	42	Containment particulate Hi-Hi radiation alarm	4
1005	190	Pressurizer level at normal, T_{avg} and pressure normal, S/G levels in manual control	5

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APPENDIX C

GRAPHS OF TRANSIENT RESPONSE

A. CONTROL ROOM CHARTS, SCALE ≃ 1 IN./HR

a. Note that time scales are not exactly the same

b. Where 2 or more signals are on the same chart, the time scales are offset. An attempt has been made to align the turbine trip time for the first or basic variable on each chart.

FIGURE C-1

Wide range S/G water level
Narrow range S/G water levels
also showing steam and feed flows

FIGURE C-2

Steam header pressure
Wide range hot leg temperatures
Wide range cold leg temperatures
Pressurizer pressure
(The compensated control pressure signal has been partially blanked out for clarity)
Pressurizer water lever

B. PLOTS FROM PLANT COMPUTER TYPED OUTPUT

0-3 Minutes: from post-trip review
9-47 Minutes: from post-accident analysis log
Alarm events are also shown to the nearest minute

FIGURE C-3

Narrow range steam generator water levels
Wide range cold leg temperatures

FIGURE C-4

RCS pressure
Pressurizer water level

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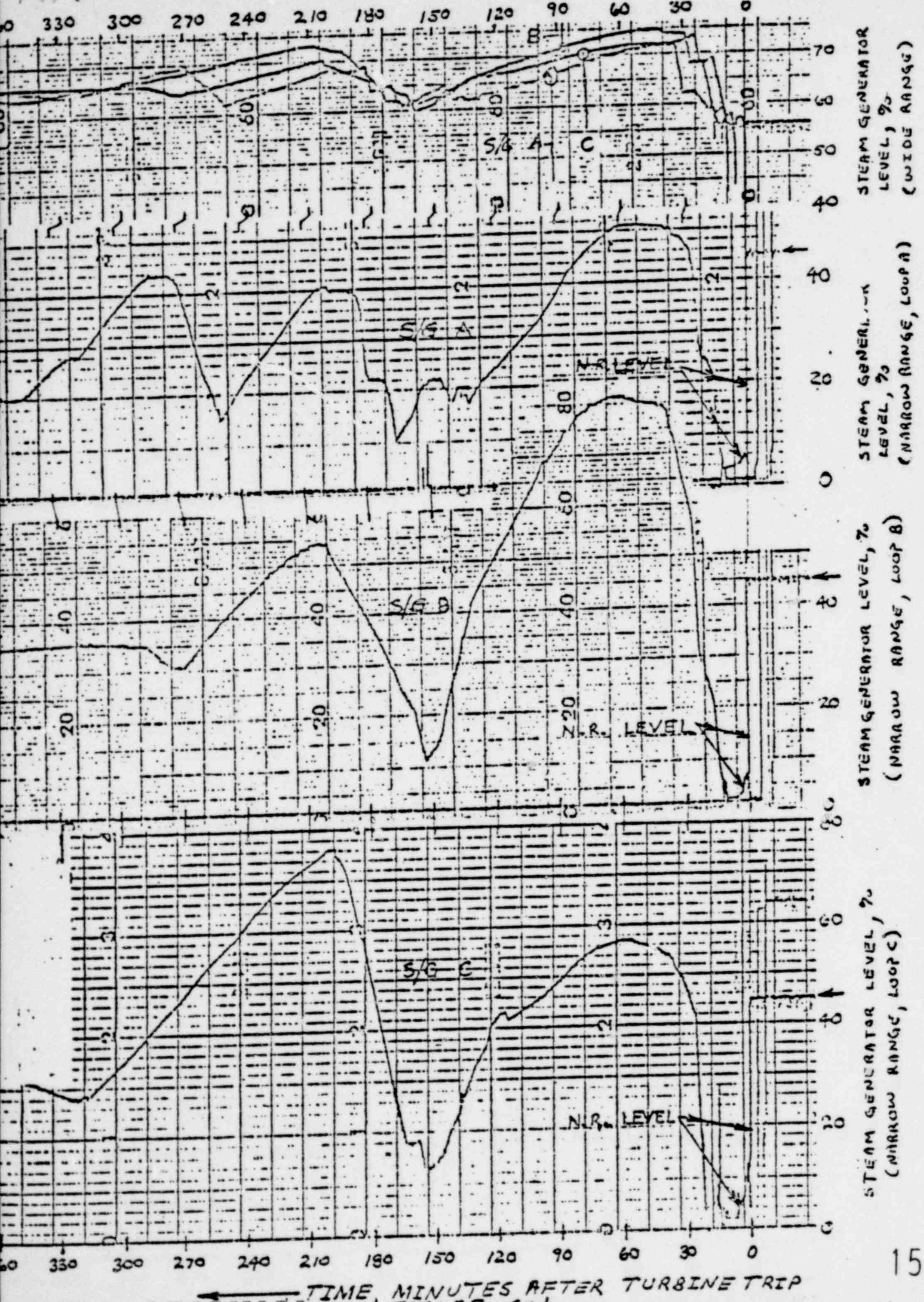

FIGURE C-1

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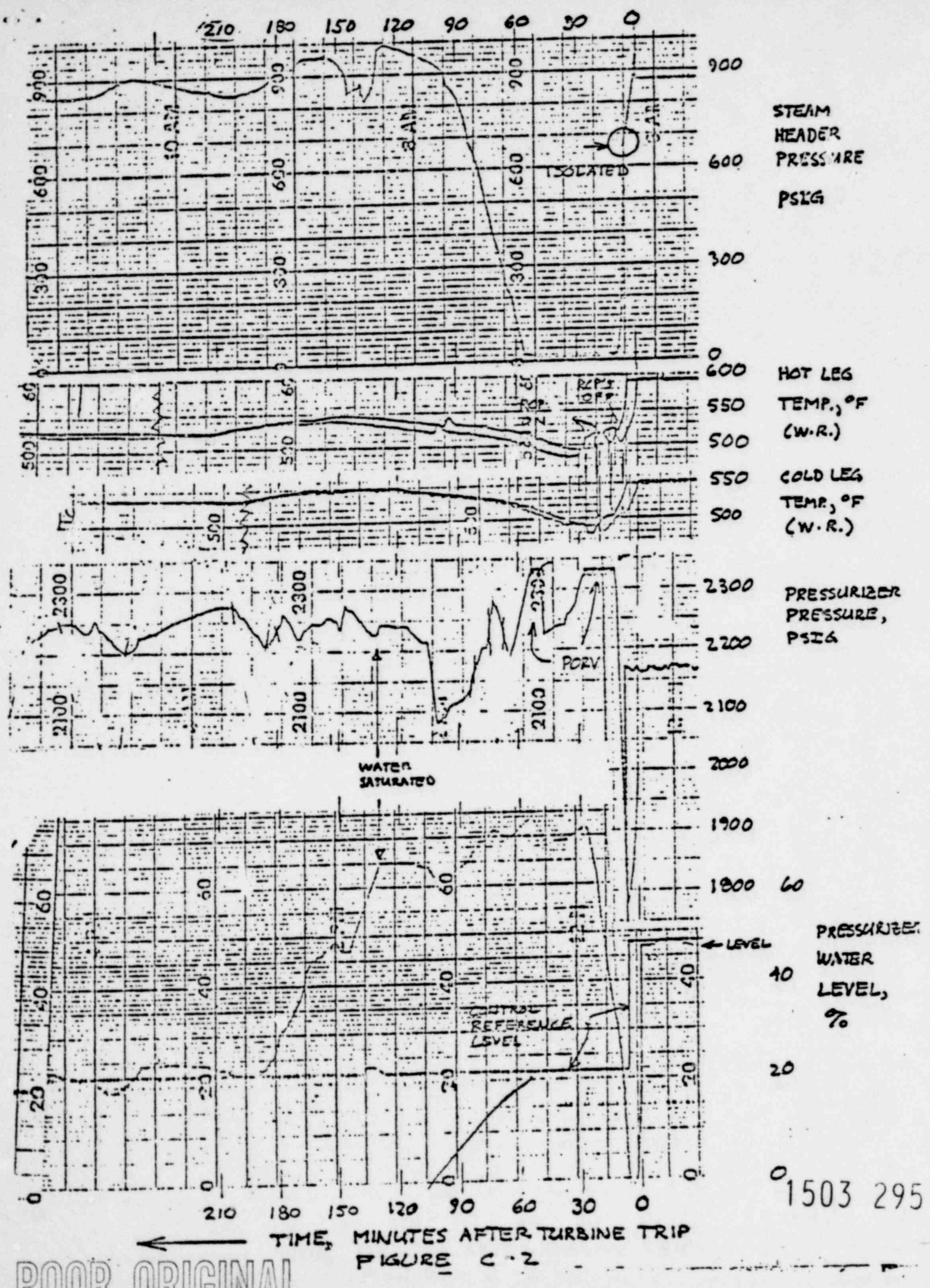

FIGURE C-2

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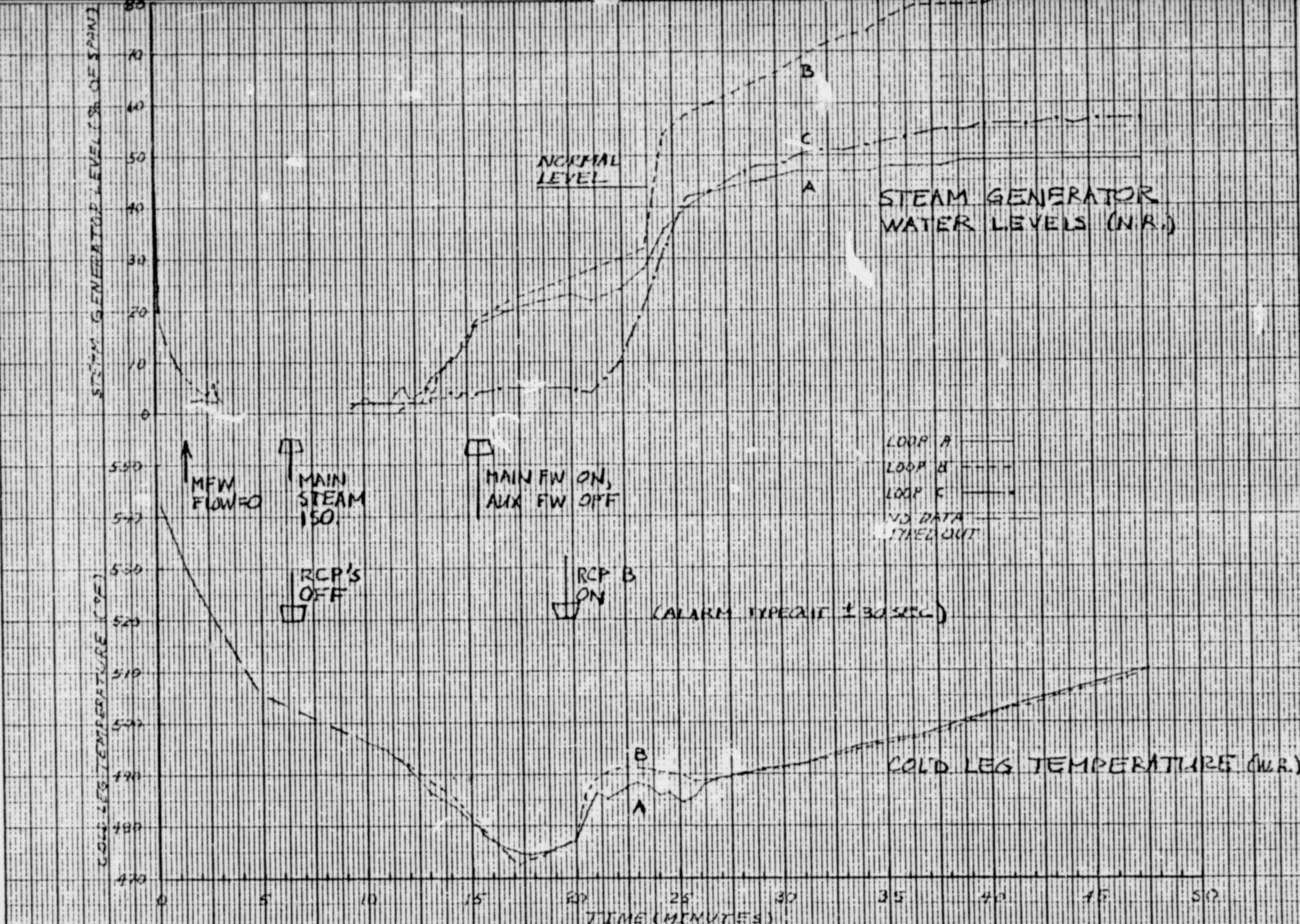

FIGURE C-3

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K+E 10 X 10 TO THE CENTIMETER 18 X 25 CM
KEUFFEL & ESSER CO. MADE IN U.S.A.

461510

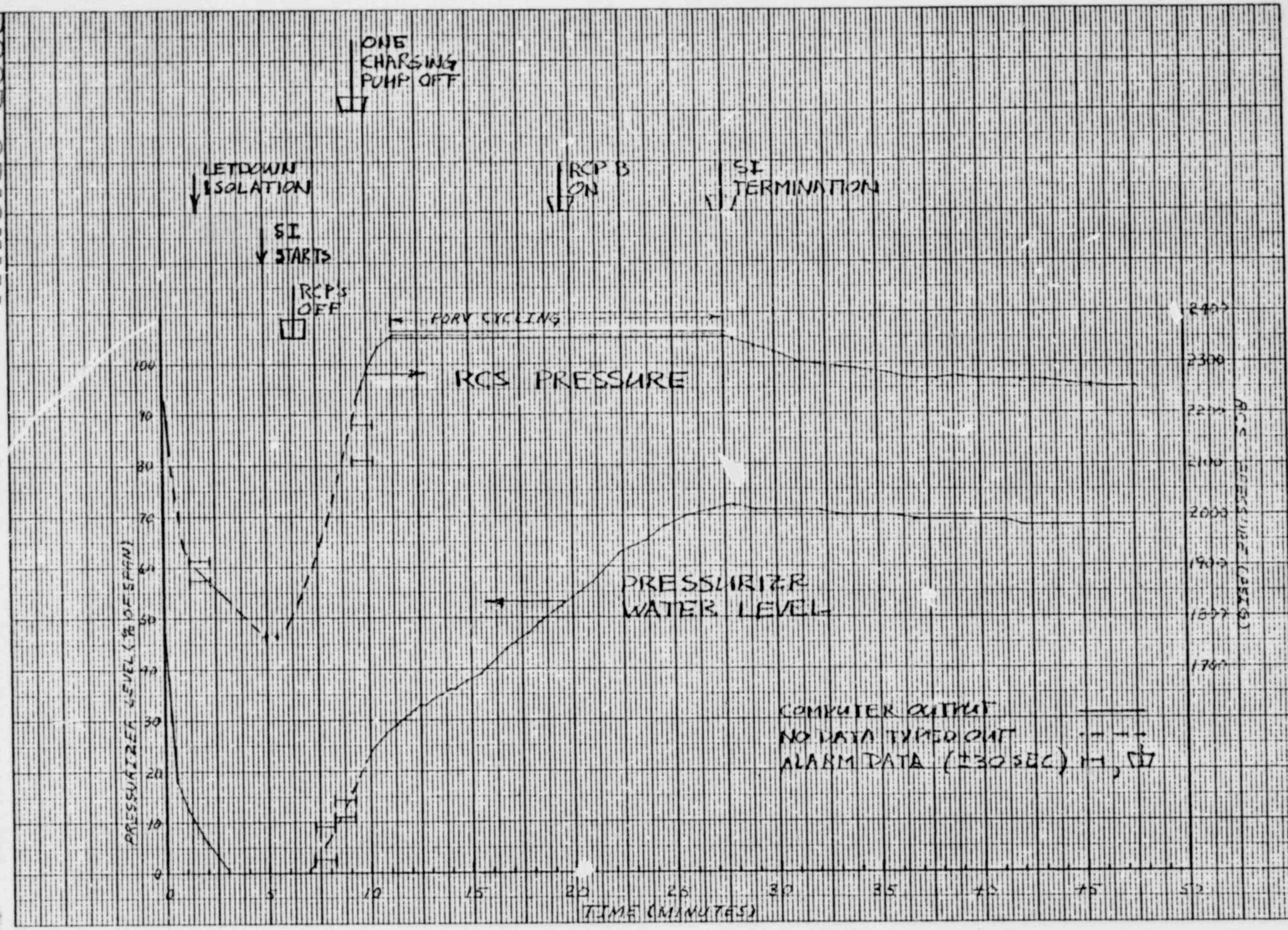

FIGURE C-4

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