UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

January 8, 1979

Docket No. 50-500/501
50-329/330

MEMORANDUM FOR: J. F. Streeter, Chief, Nuclear Support Section 1

FROM: J. S. Creswell, Reactor Inspector

SUBJECT: CONVEYING NEW INFORMATION TO LICENSING BOARDS - DAVIS-BESSE UNITS 2 & 3 AND MIDLAND UNITS 1 & 2

During the course of my inspections at Davis-Besse, certain issues have come to my attention which I am submitting for consideration for forwarding to the Atomic Safety and Licensing Board which has proceedings pending for the aforementioned facilities. This submittal is made pursuant to Regional Procedure 1530A (November 16, 1978), step 3 and information supplied to me per step 1. The issues for consideration are:

1. During a recent inspection at Davis-Besse Unit 1 information has been attained which indicates that at certain conditions of reactor coolant viscosity (as a function of temperature) core lifting may occur. The licensee informed the inspector that this issue involves other B&W facilities. The Davis-Besse FSAR states in Section 4.4.2.7:

 > The hydraulic force on the fuel assembly receiving the most flow is shown as a function of system flow in Figure 4-39. Additional forces acting on the fuel assembly are the assembly weight and a hold down spring force, which resulted in a net downward force at all times during normal station operation.

 The licensee states that there is a 500°F interlock for the starting of the fourth reactor coolant pump. However, no Technical Specification requires that the pump be started at or above this temperature. A concern regarding this matter would be if assemblies moved upward into a position such that control rod movement would be hindered.

2. Inspection Report 50-346/78-06, paragraph 4, reported reactivity - power oscillations in the Davis-Besse core. These oscillations have also occurred at Oconee and are attributed to steam generator level oscillations. B&W report BAW-10027 states in A9.2:

8006170 452

The OTSG laboratory model test results indicated that periodic oscillations in steam pressure, steam flow, and steam generator primary outlet temperatures could occur under certain conditions.

It was shown that the oscillations were of the type associated with the relationships between feedwater heating chamber pressure drop and tube nest pressure drop, which are eliminated or reduced to levels of no consequence (no feedback to reactor system) by adjustment of the tube nest inlet resistance. As a result of the tests, an adjustable orifice has been installed in the downcomer section of the steam generators to provide for adjustment of the tube nest inlet resistance and to provide the means for elimination of oscillations if they should develop during the operating lifetime of the generators. The initial orifice setting is chosen conservatively to minimize the need for further adjustment during the startup test program.

We also note that the effect on the incore detector system for monitoring core parameters during the oscillations is not clear.

3. Inspection and Enforcement Report 50-346/78-06 documented that pressurizer level had gone offscale for approximately five minutes during the November 29, 1977 loss of offsite power event. There are some indications that other B&W plants may have problems maintaining pressurizer level indications during transients. In addition, under certain conditions such as loss of feedwater at 100% power with the reactor coolant pumps running the pressurizer may void completely. A special analysis has been performed concerning this event. This analysis is attached as Enclosure 1. Because of pressurizer level maintenance problems the sizing of the pressurizer may require further review.

   Also noted during the event was the fact that Tcold went offscale (less than 520°F). In addition, it was noted that the makeup flow monitoring is limited to less than 160 gpm and that makeup flow may be substantially greater than this value. This information should be examined in light of the requirements of GDC 13.

4. A memo from B&W regarding control rod drive system trip breaker maintenance is attached as Enclosure 2. This memo should be evaluated in terms of shutdown margin maintenance and ATWS considerations particularly in light of large positive moderator coefficients allowable with B&W facilities.

5. Inspection and Enforcement Report 50-346/78-17, paragraph 6 refers to inspection findings regarding the capability of the incore detector system to determine worst case thermal conditions. The reactor can be operated per the Technical Specifications with the center incore string out of service. If the peak power locations is in the center of the core (this has been the case at Davis-Besse), factors are not applied to conservatively monitor values such as F_Q and F delta H.

6. Enclosure 3 describes an event that occurred at a B&W facility which resulted in a severe thermal transient and extreme difficulty in controlling the plant. The aforementioned facilities should be reviewed in light of this information for possible safety implications.

J. S. Creswell
Reactor Inspector

Enclosures: As stated

cc w/o enclosures:
G. Fiorelli
R. C. Knop
T. N. Tambling

Preliminary copy

TOLEDO EDISON

LOWELL E. ROE
Vice President
Facilities Development
(419) 259-5242

Docket No. 50-346

License No. NPF-3

Serial No. 475

December 22, 1978

Director of Nuclear Reactor Regulation
Attention: Mr. Robert W. Reid, Chief
Operating Reactors Branch No. 4
Division of Operating Reactors
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Reid:

In response to the December 20, 1978, telephone conversation between your Mr. Guy Vissing and our Mr. E. C. Novak, and the December 20, 1978 telephone conversation between NRC Region III personnel (G. Fiorelli, R. Knop, T. Tambling and J. Streeter) and our Mr. E. C. Novak, attached is an additional safety evaluation supporting continued operation of Davis-Besse Nuclear Power Station Unit 1. This additional safety evaluation supplements the analysis we provided to you by our letter dated December 11, 1978, Serial No. 471. The attached safety evaluation analyzes the transient resulting from the operator not controlling steam generator level at 35 inches in accordance with current operating procedures.

Yours very truly,

Lowell E. Roe

LER:CRD

Enclosure

bj e/7

dupe of 7904200034

possible dupe of 7812290165

Docket No. 50-346
License No. NPF-3
Serial No. 475
December 22, 1978

Additional Safety Evaluation
of Transient Resulting from
Inability of Operator to Control
Steam Generator Level at 35 Inches

I. INTRODUCTION

The Davis-Besse Unit 1 Steam and Feedwater Line Rupture Control System (SFRCS) design objectives are to prevent the release of high energy steam, to automatically start auxiliary feedwater (AFW), and to provide adequate AFW, via essential steam generator level control, to remove decay heat during anticipated and design basis events when AFW is required. Table 1 correlates the station variables and accident conditions for which AFW actuation is required. For all actuation signals, the SFRCS initiates and controls AFW addition automatically to maintain a 120" level (96" indicated on the startup range instrumentation) in the steam generators.

The recent natural circulation test at Davis-Besse 1 (TP800.04) demonstrated that a 35-inch (indicated) steam generator level of AFW provides adequate natural circulation for decay heat removal.

The auto essential SG level control setpoint of 120-inches (96-inch-indicated) is thus in excess of minimum SG level requirements.

Operating procedures requiring manual control of steam generator level at 35-inches on the startup range level indicators following non-LOCA events were developed and used at Davis-Besse Unit 1 pending installation of permanent design changes to the SFRCS. Margin in maintenance of indicated pressurizer level and assurance of adequate natural circulation capability will exist through operator intervention during conditions where AFW is required.

Inability of the operator to comply with the present operating procedures will possibly result in a momentary loss of pressurizer level and/or level indication under certain conditions, but will not produce consequences which are non-reversible or detrimental to safe operation of Davis-Besse Unit 1.

II. DISCUSSION

The following section is divided into three segments: Relationship with Events Presented in the Davis-Besse Unit 1 FSAR, Loss of Offsite Power, and Loss of Feedwater.

A. Relationship with events presented in the FSAR

Addition of auxiliary feedwater at rates considerably greater than the decay heat generation rate will result in overcooling of the reactor coolant, contraction and a reduction of pressurizer level. This sequence of events is typical of several transients presented in the FSAR which have been submitted to the NRC and approved as a part of the licensing process. Overcooling transients can be caused by a variety of circumstances, failures, combinations of operating equipment, and improper operator interactions. From a practical viewpoint each single discoverable possible transient cannot be analyzed and presented as a part of the FSAR analysis, but a broad variety of transients have been selected. This specific transient fits within that broad category. Each of the FSAR transients has been demonstrated to produce acceptable results.

Overcooling transients resulting from a variety of causes are described in Section 15.2.10 "Excessive Heat Removal due to Feedwater Malfunctions". This section describes a transient resulting from excessive main feedwater addition, which is similar to the specific transient of increased level addition by auxiliary feedwater. Further information is presented in response to questions 15.2.15 and 15.2.16.

The steam line break (see FSAR sections 15.4.4, 15.4.8, 15.4.1) is the most severe overcooling transient, in that the reactor coolant system is decreased 50°F in average core temperature over a 30 second time period.

This is compared with the cooldown in question, which takes a much longer time to achieve a similar temperature drop and system conditions. During the steam line break, RC system pressure is reduced from 2200 psia to about 900 psi as system temperature is driven toward equilibrium with the unaffected (pressurized) steam generator attaining saturation temperature of about 530°F. The pressurizer is near empty at about 20 seconds and thereafter loses its influence on the system, thus permitting the upper elevations of the reactor coolant loop to approach saturation as cooldown continues toward 530°F. High pressure injection (HPI) pumps are actuated on low RC pressure such that pressurizer level will be resto d. As shown in Figures 15.4.4-1 and 15.4.4-2 of the Davis-Besse Unit 1 FSAR, the rapid cooldown of RCS after reactor trip is limited by the pressure maintained in the pressurized steam generator in much the same fashion as anticipated for events such as the event of concern. As the RCS approaches saturation, core cooling is not impeded. Minimum DNBR>1.3 occurs just before reactor trip and subsequently increases with substantial margin throughout the remainder of the cooldown.

The close relationship of the auxiliary feedwater level increase as an overcooling transient with these similar overcooling transients allows us to draw the conclusion that no unreviewed safety question exists. To show a comparison to the detailed analyses reported in the FSAR, we have performed conservative bounding analyses of two representative cases.

3. Loss of Feedwater and Loss of Offsite Power

We have analyzed two transients resulting from auxiliary feedwater addition and establishment of SG level above the operating procedure 35" limit. The two transients examined are a loss of offsite power (reactor coolant pumps stop, makeup stops, main feedwater stops) and a loss of feedwater (reactor coolant pumps continue, makeup continues).

Of these two transients the loss of feedwater results in the greater volumetric coolant contraction, because the forced coolant flow (RC Pumps operating) causes a faster rate of heat rejection to the steam generator.

1. Loss of Offsite Power

Preliminary calculations for a reactor trip following a loss of offsite power show that the pressurizer loses indication but does not empty. The assumptions used to derive this result included full runout auxiliary feedwater flow (~2400 gpm) resulting in a fill time to 120" of about 4 minutes. No net mass change to the primary coolant (no makeup, no letdown) was considered, even though the makeup controls would respond to decreasing pressurizer level by increasing the net input to above 200 gpm. At the termination of the transient the pressurizer level is slightly above the outlet into the surge line. Reactor coolant pressure reaches about 1600 psi and high pressure injection may be automatically initiated.

Although the net makeup was not considered, it would in fact cause the pressurizer to refill to the normal level. At the same time compression of the steam would cause a partial repressurization of the system ensuring that the coolant remains subcooled. This transient presents no safety concerns.

2. Loss of Feedwater

This transient has a greater reactor coolant contraction than the loss of offsite power case, resulting in emptying of the pressurizer. Consequently it will be described in greater detail.

A brief summary of the events is:

• Reactor trip	Time = 0
• Makeup control valve opens wide admitting full makeup to reactor coolant system	Time = 0^{+}
• AFW initiated	Time $\approx$ 40 sec
• Pressurizer empties; RC system pressure slightly greater than 1800 psi	Time $\approx$ 2 min
• HPI initiated by SFAS; makeup isolated	Time $\approx$ 2^{+} min
• Steam generator level = 10 ft; voids exist in reactor coolant	Time $\approx$ 4 min
• HPI inflow replaces volume occupied by voids; pressurizer level begins to be restored	Time $\approx$ 7-8 min

The major concerns that evolve from this transient are the disposition of the steam voids and the approach to DNB. Both of the concerns are ameliorated by the reactor coolant pumps.

Steam voids will not collect in reactor coolant piping and no flow blockage will occur because of dispersal and mixing by the forced flow. DNB acceptance criterion limit will be met because the power output of the core is at the decay heat level and all reactor pumps are operating, maintaining core heat removal. We conclude that no safety problem exists.

TABLE 1: STEAM AND FEEDWATER LINE RUPTURE CONTROL SYSTEM (SFRCS) ACTUATION PARAMETERS

Actuation Parameter		Accident
Station Variables	Setpoint	
1. Low Steam Line Pressure	$<$ 591.6 psig[1,2]	Steam Line Break Feedwater Line Break
2. Low SG Level	$\leq$ 17 inches[1]	Loss of F/W
3. SG Pressure Minus Main Feedwater Line Pressure	$>$ 197.6 psi[1]	FWLB, LOMFW
4. Loss of All RC Pumps[3]		Loss of Off-Site Power

NOTES:

1. When actuated, SFRCS closes both main steam isolation valves, closes both main FW control and stop valves, initiates AFW and controls AFW to maintain a 120 inch level in the SGs.

2. Alignment of AFW to a pressurized SG is provided for steam and feedwater line breaks.

3. AFW initiation but steam and feedwater line isolation does not occur.

III. Bounding Analysis of Loss of Feedwater Event With Failure of Operator to Control Feedwater Level at 35"

Introduction:

The following bounding analysis conservatively predicts the events occurring within the primary reactor coolant system and reactor following a loss of main feedwater from 100% power for the Davis-Besse Unit 1. Auxiliary feedwater control has been assumed at 10 feet within both steam generators.

Results:

Because of the conservative, bounding, nature of this calculation, the overcooling of the primary system due to auxiliary feedwater injection causes a contraction of coolant volume sufficient to create steam within the primary system. The steam is shown to be uniformly distributed within the RCS and the void fraction is 4%. The reactor coolant pumps maintain full capability. The DNB ratio is shown to exceed 2.0 and no return to criticality potential exists. Thus, during the course of the incident, no core problems develop. Further, following the time of maximum contraction, the system recovers to full pressure, pressurizer function is regained and the reactor coolant returns to a subcooled water configuration without operator action.

Analysis:

The following assumptions have been made to assure the bounding nature of the results:

Reactor Power:

100% until boiling stops in the steam generators; 0% after that time. This assumption is conservative as core heat would compensate for the cooling caused by the auxiliary feedwater.

Initial Coolant Inventories Water:

RCS = 11290 ft^3

Pressurizer = 864 ft^3

These assumptions are nominal operating values.

Initial Temperatures:

The whole system is taken to be at $T_{average} = 582^{o}F$.

This assumption is a reasonable average.

Initial System Mass: ~ 500,000 lbm

The mass is figured from the temperature and volumes above.

Makeup System:

No credit is taken for additional makeup flow which will occur as the pressurizer loses level. (In all likelihood, the makeup system will contribute approximately 200 ft^3 extra liquid volume).

Local Power (kw/ft): 18.4 kw/ft

This value is taken as the maximum allowed by Technical Specifications.

Secondary Side Volume At 10 Foot Level

711 ft^3 per generator, actual volume.

Auxiliary Feedwater Flow:

166.5 ft^3/min. per generator actual value.

Auxiliary Feedwater Enthalpy:

8 Btu/lbm lower bound for maximum cooling.

With the initiating event, loss of main feedwater, the reactor coolant system pressure will start to rise. Reactor trip will occur on high RCS pressure. Following trip, the RCS pressure will fall because core power has been reduced and boiling of residual main feedwater or auxiliary feedwater is occurring in the steam generators. These events are almost identical to those which occur in a main feed line break and are analyzed in detail in Section 15.2.8 of the FSAR.

In short order, the system will return to its initial configuration but, because the auxiliary feedwater heat absorption rate exceeds the decay heat generation rate, the RCS continues to depressurize. During this phase, residual main feedwater and injected auxiliary feedwater will be boiled and vented through the steam generator safety relief valves. The primary system average temperature will fall to the saturation temperature of water at the safety valve set pressure. At this time, primary and secondary conditions are expected to be approximately as follows:

	Primary	Secondary
Pressure	1800 psia	980 psia
Temperature	542 F	542 F
Mass	503344 lbm	0 lbm
Liquid Volume in Press.	400 ft^3	N.A.
Time into Transient	$\simeq$ 2 min.	$\simeq$ 2 min.

It is conservative to assume complete boiling of the secondary side water and complete equilibrium between primary and secondary sides, as these assumptions lead to the maximum follow on injection of auxiliary feedwater and therefore, ma[illegible]mum contraction. RCS pressure is held up by the steam bubble in the pressurizer.

The time has been estimated by calculating the necessary energy loss by the primary system from its initial conditions, the mass of auxiliary feedwater required to remove this energy and then dividing by the auxiliary feedwater flow rate.

$$\text{time} \simeq \frac{(586 - 542)\ 503344}{(1194-8)\ \ 383\ \ 62} \simeq 54 \text{ sec.}$$

Six seconds was used to estimate the initial pressurization portion of the transient.

In performing the remainder of the evaluation 10 feet of cooled (40 F) auxiliary feedwater is placed in each steam generator and the thermal equilibrium condition calculated. Because after a 10 foot level is obtained this auxiliary feedwater flow stops, this condition represents the maximum contraction possible. The state variables resulting are:

	Primary	Secondary
Pressure	560 psia	560 psia
Temperature	478 F	478 F
Enthalpy of Water	462 Btu/lbm	462 Btu/lbm
Specific Volume	.020 ft^3/lbm	.020 ft^3/lbm

From the specific volume, the primary liquid volume can be calculated:

$$Vol = MV_f = 10052 \ ft^3$$

As 10052 is smaller than the RCS minus pressurizer volume, the remaining volume must be filled with steam.

$$V_{st} = 10426 - 10552 = 374 \ ft^3 \approx 400 \ ft^3$$

400 ft^3 corresponds to a system void fraction of 3.8% $\simeq$ 4%, and as will be shown later, is of no consequence as far as core heating or system performance is concerned. This steam volume is larger than actually expected for two reasons: 1) some temperature difference would always exist between the primary and secondary systems, and 2) the effect of core decay heat has been ignored. Both of these would increase the primary side liquid temperature, thus increasing its volume and reducing the steam volume.

Following this state of maximum contraction, no further heat is removed from the RCS via the secondary side until the RCS rises in temperature due to decay heating; this will expand the liquid volume, compress the steam and repressurize the RCS. As no mass can be lost from the secondary system prior to achieving 980 psia the first reheating stage will end at a primary system pressure, temperature, and liquid volume of 980 psia, 542 F, 10832 ft^3. Subtracting 10426 from 10832 shows that about 400 ft^3 of fluid has been forced back into the pressurizer. Pressurizer function would then be restored (if not directly, then, by either the makeup or HPI system), the RCS subcooled and the transient ended.

Several questions exist about the transient:

I. How is the 400 ft^3 dispersed within the primary system and can that volume collect in one location? From the auxiliary feedwater flow rate, over 4 minutes are required to fill the generators. As the pressurizer has 400 ft^3 in it at 980 psia and the RCS has 400 ft^3 in it at maximum contraction, approximately 2 minutes are used to eject steam from the pressurizer to the RCS. Because this steam will be superheated when it enters the RCS it will first desuperheat and then condense at a rate governed by its expanding pressure compared to the contraction of the liquid coolant. In the time of 2 minutes the reactor coolant will have made about 8 complete circles of the primary system and the steam can be considered well mixed. As the flow velocity in the RCS will remain normal, about 25 ft/sec, steam water separation will tend not to occur. Some limited steam accumulation may occur in the upper head of the reactor vessel as in that specific location of the RCS, velocity is low.

II. How well will the pumps work? Experiments performed on steam carry over capability show that for void fractions up to 10% no loss of pump capability is observed. This is documented in Figure 5-47 of BAW-10104, "B&W's ECCS Evaluation Report With Specific Application to 177 FA Class Plants With Lower Loop Arrangement." Actually pump capability increases for the first 5% of void introduced into the system.

III. Will any return to power be encountered because of the low RCS temperature? A return to power can occur for a non-borated core at 490F. This temperature includes the assumption of the most reactive rod stuck out of the core; if that rod were taken as inserted the critical temperature would fall to at or below 400F. Although no credit was taken for HPI in calculating the RC steam volume below 1600 psia, the HPI will be injecting borated water and, therefore, preventing any return to power condition. If the primary system were to stabilize at 1600 psia and thus prevent the HPI from providing boron the RCS temperature would be at least 511F and, therefore, no return to power would be expected.

IV. Will DNB be encountered in the core? The maximum contraction condition is again:

$P = 560$ psia
$T = 478F$
$a = 4\%$,

and occurs at least 5 minutes after power shutdown (trip occurs very early within 10 seconds of main feedwater loss). At this time, the decay heat rate is less than 3.2% using ANS + 20% (the LOCA evaluation curve). As low pressure and high void and high power are conservative bounds a DNB evaluation was performed at:

P = 500 psia
T = corresponding saturated value
a = 8%
power = 10%
W = full volumetric flow.

The resultant DNBR was >15 in the hottest channel with maximum design conditions assumed and well within acceptable values.

V. Will any steam remain trapped in the primary system? Some may be trapped for a short period of time in the upper head of the reactor vessel but this will be of no consequence and will eventually be condensed by thermal conduction through the interfacing water.

Conclusion

The maximum contraction of the RCS water has been calculated taking no credit for mitigating systems (makeup flow, HPI) and no credit for decay heating. No adverse consequences of the transient have been shown and, therefore, this transient poses no concerns to the safe operation of the plant.

IV. CONCLUSIONS

For SFRCS actuation and fill of the steam generators to the auto-essential level control point of 120" without operator action:

- No unreviewed safety question exists
- The loss of offsite power transient will not cause the pressurizer to drain although a loss of pressurizer indicated level will occur.
- The loss of feedwater transient may result in pressurize emptying, however acceptance criteria for DNB will be met. Steam bubbles which exist in the reactor coolant for a short time will be collapsed by HPI injection. Pressurizer refilling by HPI will occur.
- No return to power will result in the long term.

Babcock & Wilcox

Power Generation Group

P.O. Box 1260, Lynchburg, Va. 24505
Telephone: (804) 384-5111

June 12, 1978

SOM #382
12343
SIP #14/299

620-0014
T3.3.1

Mr. T. D. Murray, Station Superintendent
Davis-Besse Nuclear Power Station
5501 North State Route #2
Oak Harbor, Ohio 43449

Subject: CRDCS Trip Breaker Maintenance

Dear Terry:

In the past, some of our plants have experienced problems with CRDCS Trip Breakers. The problems have been traced to lack of preventive maintenance. B&W suggests that a planned, carefully executed, maintenance program be established using the maintenance program outlined in the Diamond Power CRDC System Vendor Manual. Particular attention should be directed to proper cycling, cleaning, and lubrication of the breakers.

B&W further recommends that this program be scheduled at a minimum frequency of every refueling cycle and more frequently for plants during startup, when the equipment is subject to adverse environmental conditions.

Our concern is that if proper maintenance is not accomplished, additional failures will occur resulting in an NRC demand for diverse qualified trip breakers. Also, we need to prevent all failures we can to reduce the number of lost capacity days.

If we can be of further assistance, please advise.

Yours truly,

for
F. R. Faist
Site Operations Manager

FRF:IDG:nlf
cc: W. E. Spangler
R. C. Luken
R. L. Pittman
D. A. Lee
J. S. Grant, TECo
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August 9, 1978

SOM #403 620-0014
12322 T3.3.1
SIP #14/295

file

Mr. T. D. Murray, Station Superintendent
Davis-Besse Nuclear Power Station
5501 North State Route #2
Oak Harbor, Ohio 43449

Subject: SMUD Rapid Cooldown Transient

Dear Terry:

On March 20, 1978, Rancho Seco experienced a severe thermal transient initiated by the loss of electrical power to a substantial portion of the Non-Nuclear Instrumentation (NNI). The loss of power directly caused the loss of Control Room indication of many plant parameters, the loss of input of these parameters to the plant computer, and erroneous input signals (midrange, zero, or otherwise incorrect) to the Integrated Control System (ICS).

The plant response was not the usual transient in that the ICS responded to the erroneous input signals rather than actual plant conditions, and resulted in a Reactor Protection System (RPS) trip on high pressure. Subsequent to the Reactor Trip, the erroneous signals to the ICS contributed to the rapid cooldown of the RCS. Plant operators had extreme difficulty in determining the true status of some of the plant parameters and in controlling the plant because of the erroneous indications in the Control Room.

An investigation of the events following this loss of power points out a need for a close look at operator training and emergency operating procedures for any loss of NNI power (or portion thereof). The following recommendations are made to assist your staff in a review of training and procedures to assure proper operator action for events of this nature.

1. Operators should be trained to recognize a loss of power to all or a majority of their NNI (e.g. indicators fail to mid-range, automatic or manual transfer to alternate instrument strings brings no response). The loss of power is emphasized here rather than the failure of any one instrument or control signal which are adequately covered in current simulator training courses.

2. Given that the operator can determine that electrical power has been lost to all or part of the NNI, he should know the location of the power supply breakers, and have a procedure available to quickly regain power.

3. If the fault cannot be cleared (i.e. the breakers to the power supplies reopen), the operator should have a list of alternate instrumentation available to him, and he should be thoroughly trained in its use. Examples are:

   a. ESFAS panels
   b. RPS panels
   c. ECI (Essential Controls and Instrumentation)
   d. SRCI (Safety Related Controls and Instrumentation)
   e. Remote shutdown panels
   f. Local gages
   g. Plant computer

4. Recognizing that no procedure can cover all possible combinations of NNI failures, the operator's response should be keyed to certain variables. If the operator realizes that he has an instrumentation problem (as opposed to a LOCA or steam line break, for example), he can limit the transient by controlling a few critical variables:

   a. Pressurizer Level (via HPI or normal Makeup Pumps)
   b. RCS pressure (via Pressurizer heaters, spray, E/M relief valves, etc.)
   c. Steam Generator level (via feed flow, feedwater valves, etc.)
   d. Steam Generator pressure (via turbine bypass system)

   The pressurizer level and RCS pressure assure that the Reactor Coolant System is filled; the Steam Generator level and pressure assure adequate decay heat removal.

Attachments 1 and 2 are provided to give a brief description of the events following this loss of NNI power at Rancho Seco. As can be seen by this transient, prompt precise operator action and the ability to recognize a loss of NNI power are critical factors in limiting the severity of a transient such as this.

If you have any questions or comments, please advise.

Yours truly,

Ivan D. Green

Ivan D. Green
Site Operations Manager

IDG:TFS:nlf
encl.
cc: See attached sheet.

ATTACHMENT 1

SEQUENCE OF EVENTS - SMUD 04:25 to 05:34 - MARCH 20, 1978

(Revision 1, 5/25/78)

E	EVENT
:5:35	- Lost NNI power supply cabinets 5,6, & 7
	- This caused a loss of valid signals to the ICS. BTU limits ran back feedwater, resulting in a partial loss of feedwater (actual Rx power was 72%).
	- Probable opening of "B" turbine bypass valves to the condenser (timing uncertain).
25:44	- Reactor trip on high pressure, turbine trip on interlock.
	- Pressurizer code relief setting was known to be low (approximately 2225 psig). The electromatic relief was isolated due to previous leakage problems. The data indicates primary pressure went ≈2400 psig => code relief valve lifted.
	- ICS closes main control and start-up feed valves and drive main feed pumps to minimum speed following trip.
	- Decay heat and RC pumps energy removal accomplished through generators by inventory boil off and the addition of main feedwater.
:26:15	- Pressurizer code relief valve reseats at approximately 2100 psig.
	- Operator starts HPI pump "B".
:28:23	- Operator stops HPI pump "B".
:30	- OTSG "B" pressure reaches 435 psig set-point of Steam Line Failure Logic.
	- OTSG "B" goes dry.

- Operator increases speed of a MFP and feeds "A" OTSG. This starts RCS on pressure and temperature decrease.

-

:34:25 - RC pressure ≈1900 psi

:37:16 - SFAS actuation at 1600 psig

This starts HPI, LPI and initiates emergency feed. The emergency FW pump is started and the bypass emergency FW valves are opened to full open position. The system makes no automatic attempt to control steam generator water level.

:40 - RC pressure at 1475 psig. It starts to recover from this point due to HPI. T_{ave} = 528°F.

:43:56 - "A" HPI pump secured.

:46:09 - LPI secured.

:49:54 - "A" HPI initiated. From this point on, the operator started and stopped HPI pumps as necessary to maintain pressurizer level.

:50 - Steam Line Failure Logic closes ICS-controlled start-up feed valves to each OTSG when the corresponding OTSG pressure falls below 435 psig.

:51:25 - Secured RCP-D (T_{ave} ≈435°F)
This reduced #RCP's to three

:57:27 - OTSG "A" water level - 599.7"

Speculate that ≈2 ft. of tubes are not flooded (at top) due to steam line arrangement.

:00:00 - Hourly computer log print-out
Steam temp. 380°F (OTSG "B")
Steam pressure 171 psig (OTSG "B")

Assuming $T_{ave} = T_{sat} \Rightarrow T_{ave} = 380°F$

:3:47 - OTSG "B" level - 599.1"

:34 - Power restored to NNI cabinets 5,6,47

T_{ave} = 235°F

RCS Pressure ≈2000 psig

Both OTSG full level ranges pegged high

Operator begins to reduce RC pressure using pressurizer spray.

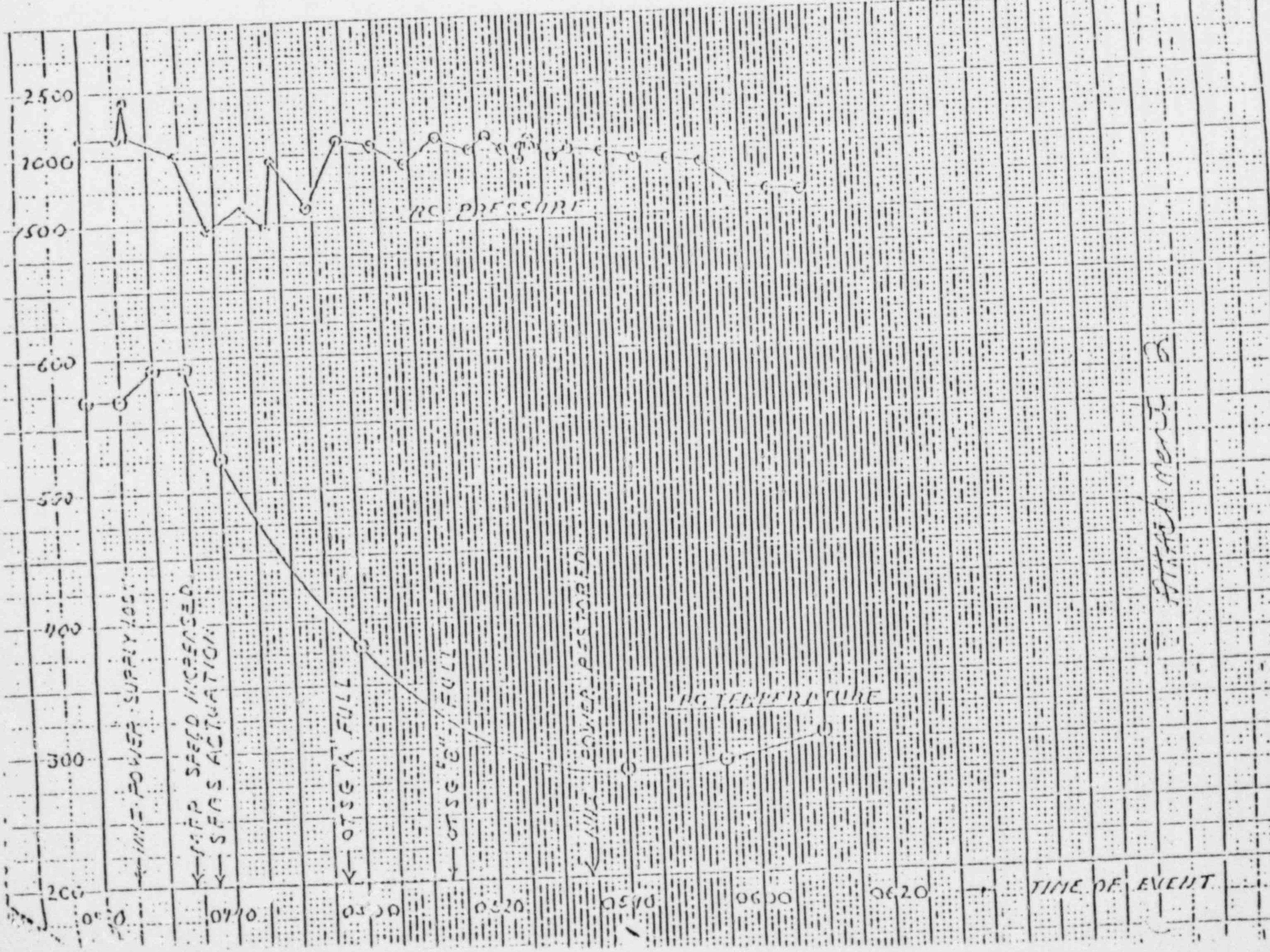
ICS closes turbine bypass valves to condenser.

Operator stops emergency FW flow.

Operator stops main FW pumps.

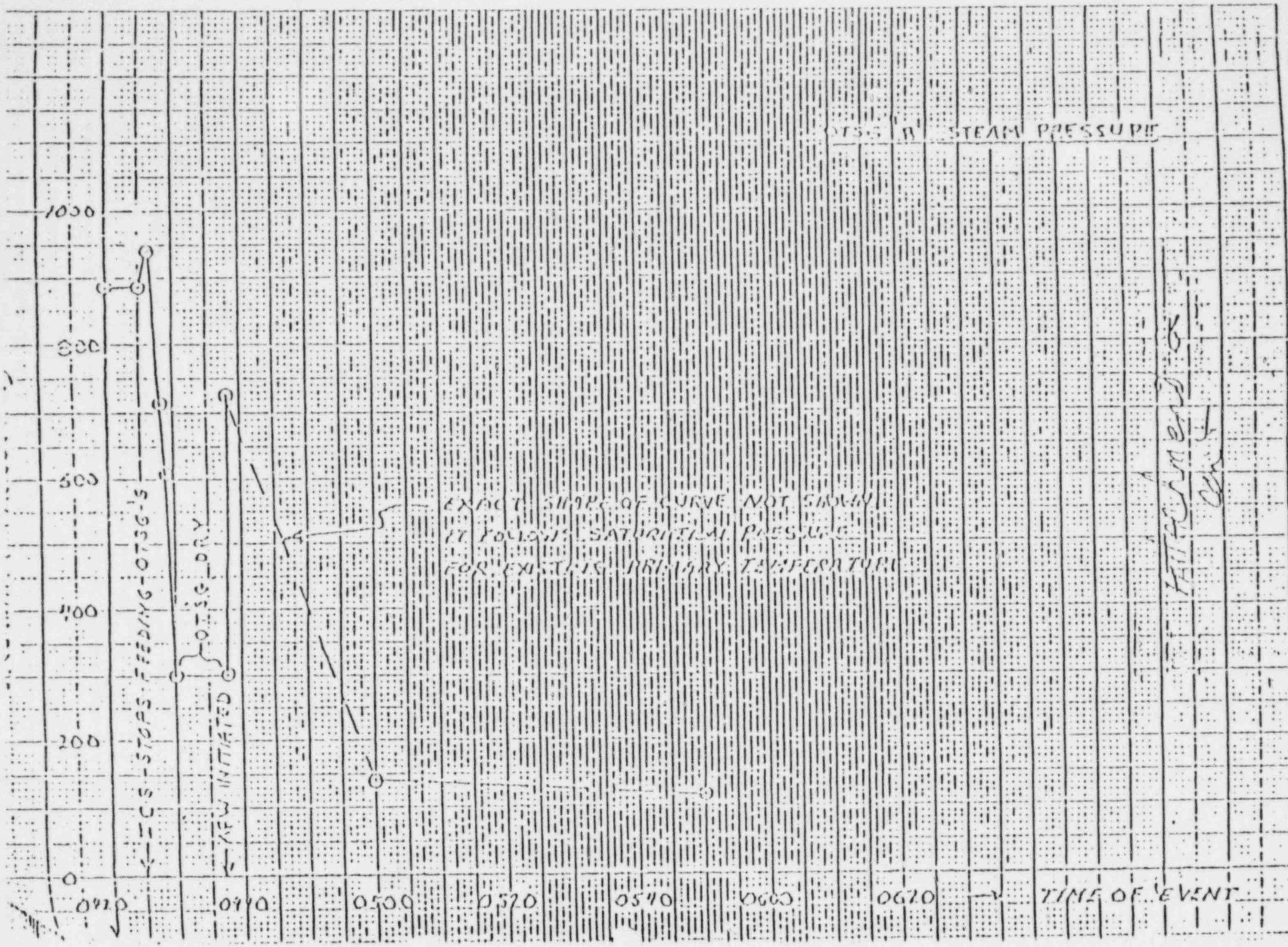
K&E 10 X 10 TO ½ INCH • 7½ X 10 INCHES
KEUFFEL & ESSER CO.

46 1470



K+E 10 X 10 TO ½ INCH • 7½ X 10 INCHES KEUFFEL & ESSER CO.

46 1470



K-E 10 X 10 TO ½ INCH 46 1470