NORTHEAST UTILITIES
The Connecticut Light And Power Company
Western Massachusetts Electric Company
Holyoke Water Power Company
Northeast Utilities Service Company
Northeast Nuclear Energy Company

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Re: 10CFR50.73(a)(2)(iv)
January 30, 1991
MP-91-93

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Reference: Facility Operating License No. NPF-49
Docket No. 50-423
Licensee Event Report 90-030-00

Gentlemen:

This letter forwards Licensee Event Report 90-030-00 required to be submitted within thirty (30) days pursuant to 10CFR50.73(a)(2)(iv), any event or condition that resulted in manual actuation of any Engineered Safety Feature (ESF), including the Reactor Protection System (RPS).

Very truly yours,

NORTHEAST NUCLEAR ENERGY COMPANY

FOR: Stephen E. Scace
Director, Millstone Station

BY: Carl H. Clement
Millstone Unit 3 Director

SES/TGM:mo

Attachment: LER 90-030-00

cc: T. T. Martin, Region I Administrator
W. J. Raymond, Senior Resident Inspector, Millstone Unit Nos. 1, 2 and 3
D. H. Jaffe, NRC Project Manager, Millstone Unit No. 3

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NRC Form 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

Estimated burden per response to comply with this information collection request: 50.0 hrs. Forward comments regarding burden estimate to the Records and Reports Management Branch (p-530), U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Millstone Nuclear Power Station Unit 3	0 5 0 0 0 4 2 3	1 OF 0 5

TITLE (4): Manual Reactor Trip Due to Moisture Separator Reheater Piping Line Breaks

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	
1 2	3 1	9 0	9 0	- 0 3 0	- 0 0	0 1	3 0	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 8 6

THIS REPORT IS BEING SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.402(c)	X 50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Terry McNatt, Engineer, Ext. 5592	AREA CODE 2 0 3 - 4 4 7 - 1 7 9 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)

X YES (If yes, complete EXPECTED SUBMISSION DATE) ☐ NO

EXPECTED SUBMISSION DATE (15): MONTH 0 5 | DAY 0 1 | YEAR 9 1

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On December 31, 1990, at 1636 hours with the plant in Mode 1 at 86% power, 580 degrees Fahrenheit and 2250 psia, a manual reactor trip was initiated due to two six inch Moisture Separator Drain line (DSM) piping breaks in the Turbine Building. Following the trip a Main Steam Line Isolation was initiated to minimize the release of steam into the Turbine Building.

The cause of the event was the failure of the two DSM lines downstream of the respective level control valves. Both lines appeared to burst, fail longitudinally, then unzip circumferentially at the minimum wall thickness location. The wall thickness at the rupture was approximately 0.020 inches. The cause of the severe wall loss was single phase erosion/corrosion. The combination of temperature, high fluid velocity and extremely low oxygen content are the causative factors. The wall loss was localized. The minimum thickness occurred adjacent to the control valve(s) and increased at 0.011 inches per inch downstream from the valve(s). The root cause analysis of the event has not been completed.

As immediate corrective action control room operators performed the actions required by the applicable emergency operating procedures. The ruptured pipes were capped pending repairs during the upcoming outage. The DSM pumps and piping were isolated. Potential long term corrective actions will be evaluated when the root cause analysis is complete.

I. Description of Event

On December 31, 1990, at 1636 hours with the plant in Mode 1 at 86% power, 580 degrees Fahrenheit and 2250 psia, a manual reactor trip was initiated due to two six inch Moisture Separator Reheater drain line (DSM) piping breaks in the Turbine Building. Following the trip a Main Steam Line Isolation was initiated to minimize the release of steam into the Turbine Building. Breaks occurred in lines downstream of the respective level control valves 3DSM-LV20A1 and B1, due to severe wall thinning caused by erosion/corrosion (refer to Figure 2). The piping failure resulted in the release of approximately 127,000 gallons of steam/water from the condensate piping and hotwell and 65,000 gallons of water from the condensate surge tank. The thermal energy of the fluid released from the ruptured piping activated the fire protection sprinkler system releasing an additional 25,000 gallons of water into the Turbine Building. In addition to mechanical and electrical damage in the Turbine Building, a power loss caused the isolation of instrument air to the containment, resulting in the loss of normal pressurizer spray flow and the isolation of normal letdown flow. Reactor Coolant Pump Seal Injection was reduced to the minimum allowable. Pressurizer level and pressure increased. One Power Operated Relief Valve (PORV) lifted three times to control reactor coolant system pressure.

At the time of the trip, operators verified that the reactor trip and bypass breakers were open, that all control rods were fully inserted, and that neutron flux was decreasing. An Auxiliary Feedwater actuation occurred as a result of steam generator low-low level signals. This is a normal plant response following a trip from 86% power. A Main Steam Line Isolation was manually initiated due to the line break in the Turbine Building. No additional engineered safety features were required or initiated. There was no operational, maintenance, or construction activities in progress at the time which affected the event. The plant stabilized at approximately 1841 hours based on stable reactor coolant system temperatures, the restoration of normal letdown flow, and restoration of normal pressurizer pressure control.

II. Cause of Event

The cause of the failure of the DSM lines was severe wall thinning downstream of the control valves. The wall thickness of the carbon steel, six inch, schedule 40 pipe had decreased from a nominal thickness of 0.280 inches to 0.020 inches at the failure sites. The cause of the thinning is attributed to single phase erosion/corrosion. A number of factors contributed to the erosion/corrosion including piping design, fluid temperature, high fluid velocity, and oxygen content of the fluid. Original piping design in the early 70's had not considered the significant reductions in fluid oxygen levels that would be achieved by the time the unit was ready for operation. The minimum thickness occurred adjacent to the control valve(s), and increased by 0.011 inches per inch downstream from the valve(s).

The configuration of the failed piping was a horizontal run of 10" piping which reduced to 6" piping upstream of a 6" control valve. The 6" piping extended up to a 6" manual isolation valve, then expanded to 10" piping, before tying into the Condensate System. While it is normal to reduce the line size of piping directly upstream of a control valve, in typical piping designs, the piping is increased to the original line size immediately downstream of the associated control valve (see Figure 2). The fluid velocity in the piping downstream of the control valves has been calculated to be in the range of 17 ft/sec, which when coupled with the low oxygen levels produces a high erosion rate.

An erosion/corrosion monitoring and inspection program for these non-safety related piping systems was developed and has been in use following the failure of non-safety related piping at Surry in 1986. NRC Notice 86-106, Generic Letter 89-08 and other documents aided in this development by providing information regarding computer programs such as the EPRI CHEC program to predict piping areas susceptible to single phase erosion/corrosion and the developmental MIT program. The DSM piping system was not entered into these monitoring and inspection programs. We are continuing to evaluate the reason for this.

III. Analysis of Event

This event is being reported in accordance with 10CFR50.73(a)(2)(iv) as an event or condition that resulted in manual or automatic actuation of any Engineered Safety Feature, including the Reactor Protection System. An immediate notification was made in accordance with 10CFR50.72(b)(2)(ii).

There were no significant safety consequences due to this event. The loss of instrument air to Containment resulted in a loss of normal non-safety related pressurizer pressure and level control. As a result, pressurizer pressure increased to the PORV setpoint. The PORV's functioned as designed to prevent pressure increases beyond the PORV setpoint. The safety grade letdown flowpath was available, but it was not used because restoration of the normal flowpath was expected. After the PORV cycled the second time, both the valve open and valve closed lights on the main control boards remained illuminated. PORV discharge tailpiece temperature was used to verify the PORV had reseated. The loss of power in the Turbine Building led to a loss of power to the plant process computer, rendering the Safety Parameter Display System (SPDS) unavailable. Control Room operators used the backup status trees to verify critical status functions. Monitoring functions normally performed by the computer were performed manually until power was restored to the computer.

IV. Corrective Action

The damaged sections of pipe were removed. Temporary pipe caps of a material consistent with the original system design were installed. The plant returned to power utilizing the Moisture Separator drain system alternate drain lines. (See Figure 1).

The erosion/corrosion program was reviewed to verify that no other systems or portions of systems were omitted from the erosion/corrosion analysis. The affected DSM lines were added to the inspection program. Prior to the restart of the plant, nondestructive examinations were performed on the remaining sections of piping, on welds upstream and downstream of the failed piping, on piping in areas with similar configurations, and downstream of the alternate drain line control valves. The DSM piping downstream of the alternate drain line control valves will be inspected again during the refueling outage (scheduled for February, 1991).

The complete erosion/corrosion program will be remodeled using the CHECMATE program. The CHECMATE inspection output will be analyzed to identify any piping that should be inspected prior to returning to service after the refueling outage. Permanent repairs will be made to the DSM piping during the outage.

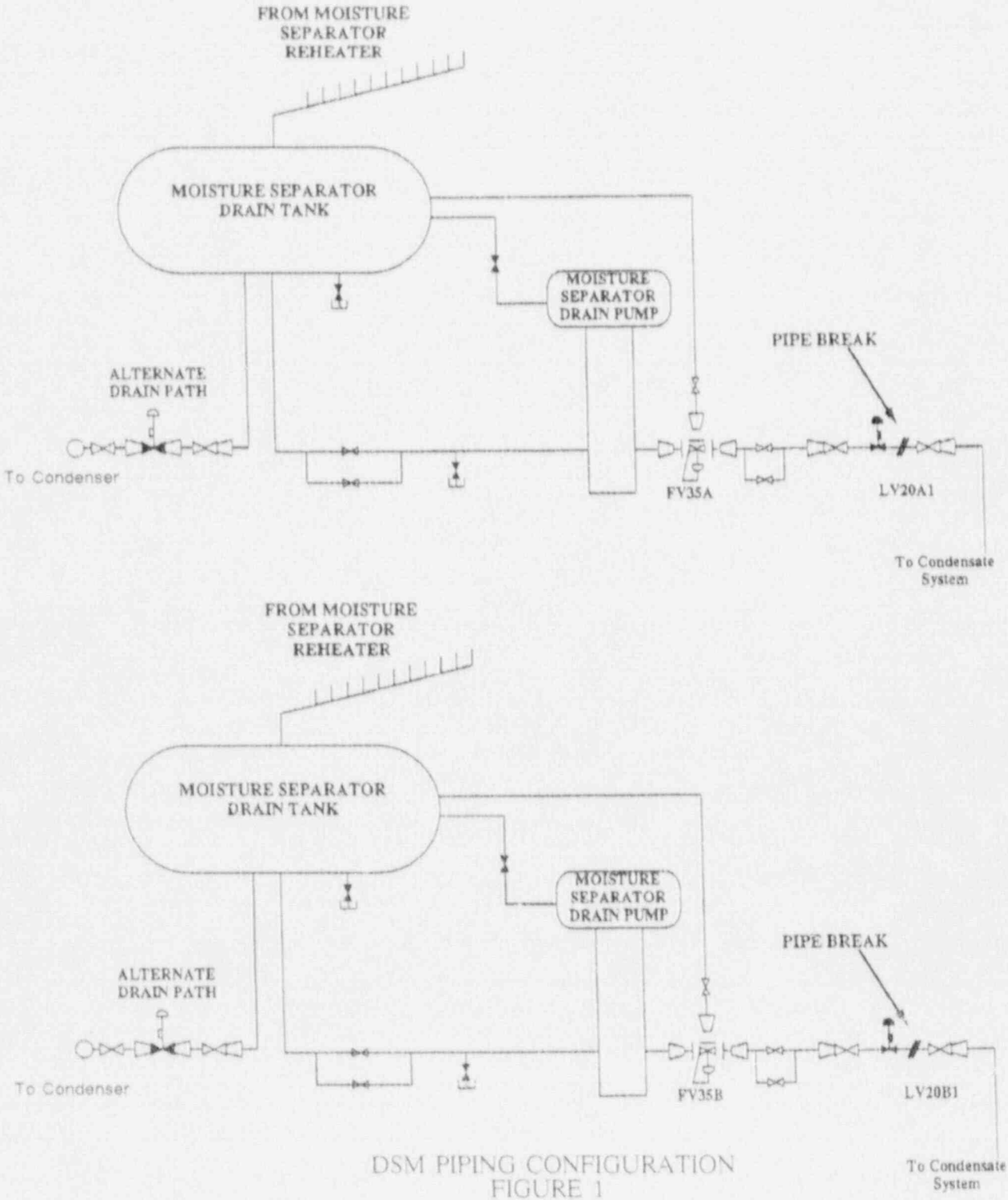
A multi-disciplined Engineering task force was formed to investigate the root cause of the event. Potential long term corrective actions will be evaluated following completion of the root cause analysis. A supplemental report will be submitted by May 1, 1991, detailing the results of the root cause analysis and any additional corrective action.

V. Additional Information

Similar events will be determined following root cause analysis completion.

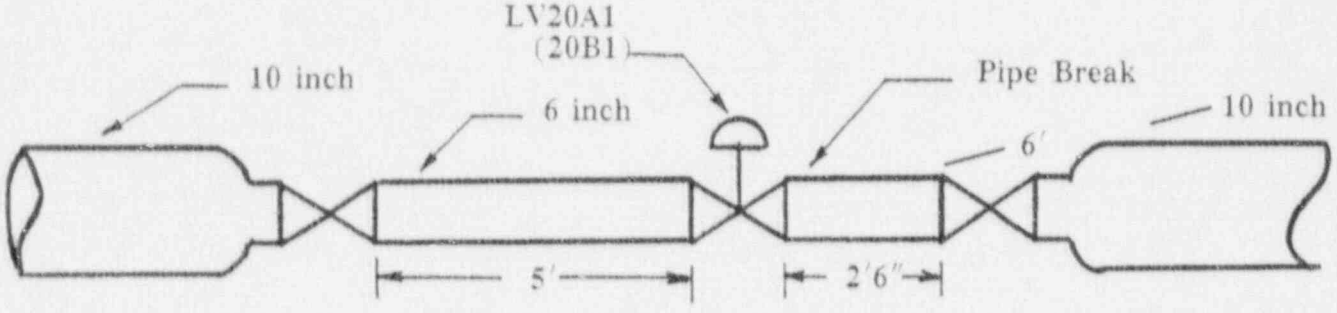
EIIS Codes

System	Component
Main Steam Reheat System-SB	Level Control Valves-LCV

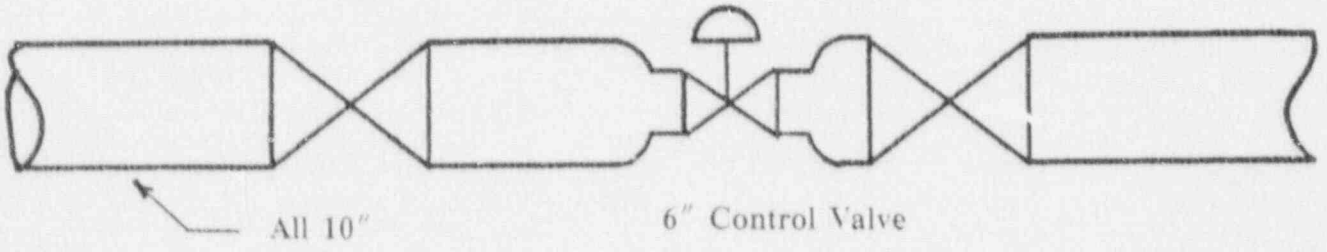


DSM PIPING CONFIGURATION
FIGURE 1

DSM Control Valve Piping Configuration



Typical Control Valve Piping Configuration



DSM VS. TYPICAL PIPING CONFIGURATION
FIGURE 2