UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. (Indian Point Unit No. 2)	)	Docket No. 50-247
	)	

CONSOLIDATED EDISON'S
ANSWER TO NOTICE OF PROPOSED
<u>IMPOSITION OF CIVIL PENALTY</u>

January 5, 1981

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. (Indian Point, Unit No. 2)	)	Docket No. 50-247

CONSOLIDATED EDISON'S
ANSWER TO NOTICE OF PROPOSED
IMPOSITION OF CIVIL PENALTY

Pursuant to 10 CFR 2.205(b) and the Notice of Violation and Proposed Imposition of Civil Penalty dated December 11, 1980, Consolidated Edison Company of New York, Inc., provides the following written answer. The answer to each alleged violation incorporates by reference the corresponding response to that item set forth in Consolidated Edison's Statement in Reply to the Notice of Violation (hereinafter referred to as "Statement").

Alleged Violation I.A: Consolidated Edison admits that this item is a violation. Consolidated Edison denies that this item is a Severity Level III violation under the October 7, 1980 Interim Enforcement Policy (hereinafter referred to as "Policy"). Consolidated Edison believes that there are extenuating circumstances and requests remission or mitigation of any penalty proposed in accordance with the Policy. See Statement, pp. 2-11.

Alleged Violation I.B: Consolidated Edison denies that this item is a violation. See Statement, pp. 13-16.

Alleged Violation II.A: Consolidated Edison admits that this item is a violation. Consolidated Edison denies that this item is a Severity Level III violation under the Policy. Consolidated Edison believes there are extenuating circumstances and requests remission or mitigation of any penalty proposed in accordance with the Policy. See Statement, pp. 18-22.

Alleged Violation II.B: Consolidated Edison denies that this item is a violation. See Statement, pp. 26-37.

Alleged Violation II.C: Consolidated Edison denies that this item is a violation. See Statement, pp. 39-42.

Alleged Violation II.D: Consolidated Edison denies that this item is a violation. See Statement, pp. 45-50.

Alleged Violation II.E: Consolidated Edison denies that this item is a violation. See Statement, pp. 53-55.

Alleged Violation II.F: Consolidated Edison admits that this item is a violation. Consolidated Edison denies that this item is a Severity Level III violation under the Policy. Consolidated Edison believes that there are extenuating circumstances and requests remission or mitigation of any penalty proposed in accordance with the Policy. See Statement, pp. 58-60.

Alleged Violation III.A: Consolidated Edison denies that this item is a violation. See Statement, pp. 63-67.

Alleged Violation III.B: Consolidated Edison admits that this item is a violation. Consolidated Edison denies that this item is a Severity Level III violation under the Policy. Consolidated Edison believes that there are extenuating circumstances and requests remission or mitigation of any penalty proposed in accordance with the Policy. See Statement, pp. 68-70.

Alleged Violation IV: Consolidated Edison admits that this item is a violation. Consolidated Edison denies that this item is a Severity Level V violation under the Policy. See Statement, pp. 72-73.

Affirmative Defense No. 1: The December 11, 1980 Notice of Violation and Proposed Imposition of Civil Penalty does not apply the Policy according to its terms.

Affirmative Defense No. 2: The NRC was aware of and did not object to Consolidated Edison's program of maintenance and detection of leaks in its service water system at Indian Point 2 as it existed prior to October, 1980 by review and regulatory oversight of the program and associated maintenance history documentation.

Affirmative Defense No. 3: The NRC's Policy as applied to Consolidated Edison herein is vague and indefinite, and does not give Consolidated Edison adequate notice of the standards by which its conduct is to be judged.

Affirmative Defense No. 4: The NRC's Policy as applied to Consolidated Edison herein is punitive, and is not confined to remedial purposes.

Based upon the foregoing answer, Consolidated Edison respectfully requests that the Office of Inspection and Enforcement dismiss those alleged violations which are denied herein, and reduce the cumulative amount of the remaining civil penalties which have been proposed.

Respectfully yours,

John D. O'Toole

John D. O'Toole
Assistant Vice President
Consolidated Edison Company
of New York, Inc.

Dated: New York, New York
January 5, 1981

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
631 PARK AVENUE
KING OF PRUSSIA, PENNSYLVANIA 19406

MAY 0 4 1981

Docket No. 50-247

Consolidated Edison Company of New York, Inc.
ATTN: Mr. John D. O'Toole
Vice President - Nuclear Engineering
and Quality Assurance
4 Irving Place
New York, New York 10003

Gentlemen:

Subject: Investigation 50-247/80-19

This refers to your letter dated April 3, 1981, in response to Mr. Victor Stello's letter dated March 2, 1981.

Thank you for providing us with a supplemental response which details and clarifies your corrective and preventive actions that were documented in your letter of January 5, 1981. Additionally, in a phone conversation on April 17, 1981 between Mr. J. C. Higgins of our office and Mr. G. Wasilenko of your staff, the below further clarifications were obtained. With regard to Item II.C, we understand that your evaluation of the causes of malfunctions in safety-related systems will not be limited to significant equipment malfunctions and that per ANSI N18.7-1976 the causes of malfunctions will be promptly determined, evaluated and recorded. With regard to Item II.F, we understand that your system of material control identifies each safety-related item in the plant and provides controls to ensure that the proper item is used for replacement or repair of any safety-related item.

If our understandings are incorrect, please inform us immediately. Your corrective and preventive actions will be examined in a subsequent inspection of your licensed program.

Your cooperation with us is appreciated.

Sincerely,

Boyce H. Grier
Boyce H. Grier
Director

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cc:
C. W. Jackson, Vice President, Nuclear Power
K. Burke, Director, Regulatory Affairs
W. D. Hamlin, Assistant to Resident Manager (PASNY)
F. Matra, Resident Construction Manager, Indian Point
R. P. Remshaw, Nuclear Licensing Engineer
Joyce P. Davis, Esquire
Brent L. Brandenburg, Assistant General Counsil

bcc:
IE Mail & Files (For Appropriate Distribution)
Central Files
Public Document Room (PDR)
Local Public Document Room (LPDR)
Nuclear Safety Information Center (NSIC)
Technical Information Center (TIC)
REG:I Reading Room
State of New York
NRC Resident Inspector
Chief, Operational Support Section
V. Stallo, IE
J. Soriezek, IE
J. Riesland
L. Olshan, NRR, ORB-1
J. Higgins, RI

John D. O'Toole
Vice President

Consolidated Edison Company of New York, Inc.
4 Irving Place, New York, NY 10003
Telephone (212) 460-2533

Letter No. 81-68

April 3, 1981

Re: Indian Point Unit No. 2
Docket No. 50-247

Mr. Victor Stello, Jr., Director
Office of Inspection and Enforcement
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Stello:

Your letter of March 2, 1981 requested supplemental responses regarding certain corrective measures proposed in our January 5, 1981 letter concerning the October 1980 accumulation of service water inside containment at Indian Point Unit No. 2. We understood your letter to require a supplemental corrective measures discussion prior to unit re-start. After discussions with members of your staff on March 27, 1981, it was agreed that the requested information would be supplied on this date. Enclosure 1 to this letter contains the information requested.

Should you or your staff have any questions regarding this information, please contact us.

Very truly yours,

John D. O'Toole

Subscribed and sworn to before me this 3 day of April 1981

David Watson

Notary Public

DAVID WATSON
Notary Public State of New York
No. 03-4604876
Qualified in Bronx County
Commission Expires March 30, 1983

cc: Mr. Samuel J. Chilk, Secretary to the Commission
Mr. William J. Dircks, Executive Director for Operations
Mr. Boyce H. Grier, Director Region 1
Mr. Theodore Rebelowski, Resident Inspector

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ENCLOSURE 1

Supplemental Responses for
Corrective Measures Proposed
in Con Edison's January 5, 1981 Letter

RESPONSE TO ITEM II.A

Station Administrative Order (SAO) No. 131, entitled Station Nuclear Safety Committee (SNSC), sets forth the organization, responsibilities and functions of SNSC. The organization and responsibilities of the Committee have been revised to ensure that the Committee will conduct further reviews of potential safety hazards prior to bringing the plant critical and to provide for greater independence of the Committee from those directly responsible for plant operation. The responsibilities of the Committee have been revised to require that the plant not be brought critical without SNSC consideration and approval if the Senior Watch Supervisor or the Shift Technical Advisor has not positively identified the cause of the reactor trip, has determined that startup may involve unusual conditions or has any reason to believe that a potential safety hazard exists.

The organization of SNSC has been modified to provide that the General Manager, Technical Support is the Committee Chairman. Formerly, the Plant Manager was the Chairman. This change in the Committee organization should enhance SNSC independence from personnel primarily responsible for the plant operations.

The Shift Technical Advisors now report to the General Manager, Technical Support. As indicated above, the Shift Technical Advisor may require that the SNSC give its consideration and approval prior to allowing the plant to be brought critical if the STA believes that a potential safety hazard exists.

RESPONSE TO ITEM II.B.2

System Operating Procedure 1.7, entitled Leakage Surveillance and Safety Evaluation, has been revised to reflect the concerns expressed by the NRC in its inspection report, the modifications to the equipment used to detect leakage inside containment, and the revisions to plant Technical Specifications. The frequency of performance of the leakage surveillance calculation has been increased from daily to once per shift. Action levels have been included in the procedure to assure compliance with Technical Specifications proposed by our letter dated March 26, 1981. Calibration procedures for the high level alarms on the fan cooler unit weir level have been included in the Instrumentation and Control Sections PM-181.

A new dew point recorder will be installed in the Control Room prior to plant restart which will permit recording dew point less than 70°F. The lowest reading on the dew point recorder will be 30°F, which is low enough to assure that the recorder will not be "off scale low". The calibration procedures for the dew point system's humidity detection alarms have been included in PM-298.

RESPONSE TO ITEM II.B.4

The Maintenance Section's Administrative Directive MAD-4, entitled Procedures for Performing Maintenance, has been amended to provide additional guidance as to when written approved procedures are required for maintenance and repair and when a maintenance or repair activity constitutes a modification. MAD-4 was revised to include the definition of modification contained in Corporate Instruction CI-240-1. The directive was also changed to increase the scope of maintenance and repair activities for which written procedures are required and to require that unless the Maintenance Engineer or his designated alternate approves, a maintenance or repair activity will not be performed without a written approved procedure. The directive specifies that maintenance and repair activities can be performed without written procedures only if the activity requires skills normally possessed by maintenance personnel and if the activity does not constitute a modification. Written approved procedures are required for all modifications. The Station Nuclear Safety Committee is required to conduct a pre-implementation review of maintenance and repair procedures which involve safety related components or their operation, unless an emergency exists and prior approval is received from the General Manager, Nuclear Power Generation, Chairman of the Station Nuclear Safety Committee or the Vice President-Nuclear Power.

RESPONSE TO ITEM II.C

The Corporate Instruction that establishes and defines the Con Edison Quality Assurance Program for Operating Nuclear Plants has been revised to provide new guidance for determining, evaluating and resolving nonconformances, and for determining and recording the cause of significant nonconformances, including significant equipment malfunctions. Nonconformance reports that identify significant conditions adverse to quality require that organizations such as Engineering, Nuclear Power and Nuclear Engineering determine and evaluate the cause of the conditions and conduct appropriate follow-up action. Quality Assurance & Reliability (QA&R) and the Station Nuclear Safety Committee (SNSC) conduct periodic, systematic reviews of nonconformance reports pertaining to safety-related equipment malfunctions and their repair. Results of these reviews will be documented and submitted to the management of the affected organization. The Corporate Instruction sets forth controls for initiating, processing and responding to nonconformance reports, as follows:

- Definition and classification of nonconformances
- Responsiblities and authorities of organizations that initiate and process nonconformance reports
- Time periods for reporting certain types of nonconformances
- Target time periods for responding to nonconformance reports
- Action to be taken on late or inadequate responses
- Escalation of nonconformance reports to significant nonconformance status, where appropriate
- Audits of corrective action identified in nonconformance reports

RESPONSE TO ITEM II.D

The Corporate Instruction that establishes and defines the Con Edison Quality Assurance Program for Operating Nuclear Plants will be revised prior to plant restart to enhance the review, for safety implications of Maintenance Work Requests (MWRs) involving major maintenance and major repairs of plant safety-related items. The Corporate Instruction will require an engineering safety evaluation of modifications and associated work procedures, new materials, and changes. The revised Corporate Instruction will require that the General Manager, Nuclear Power Generation submit applicable MWRs to the General Manager, Technical Support for review to determine the scope of 10CFR50.59. If the General Manager, Technical Support determines that 10CFR50.59 may apply, he will forward a request to Nuclear Engineering for a safety evaluation. Nuclear Engineering will review the material and either perform a safety evaluation or determine that no safety evaluation is required. Nuclear Engineering will maintain records of such evaluations and determinations and send copies of the evaluation/determination reports to the Station Nuclear Safety Committee (SNSC), the Nuclear Facilities Safety Committee (NFSC), the General Manager, Nuclear Power Generation and the General Manager, Technical Support.

The Corporate Instruction is also being revised to require that QA&R and SNSC conduct periodic, systematic reviews of equipment malfunctions and their repairs. These reviews will include evaluation of pertinent MWRs and nonconformance reports, e.g., Licensee Event Reports (LERs), Deficiency Reports (DRs), Quality Control Inspection Reports (QCIRs).

The above changes will provide additional assurance that maintenance receives appropriate reviews relative to 10CFR50.59.

RESPONSE TO ITEM II.F

The cause of the material misidentification which occurred in 1976 could have been attributable to inadequate drawing or material specification control and/or to improper identification and control of replacement material. In order to enhance drawing and material control, the Corporate Instruction that establishes and defines the Con Edison Quality Assurance Program for Operating Nuclear Plants was revised in 1979 to provide new guidance for controlling drawings and material lists used directly in accomplishing work on safety-related plant items. This new guidance requires that a project drawing list identifying design documents approved by Engineering be maintained for work in progress in major projects, and that identification of field conditions be authorized by Engineering, in sketches, drawings or specifications. The instruction sets forth time periods for collecting and reporting (to Engineering) "as constructed" information for updating of drawings by Engineering, and for distribution of revised drawings. This revision also provides guidance on reporting, reviewing and apprising Engineering of field variations from design documents, and on Engineering resolution of the reported conditions to achieve consistency document and the condition.

The Corporate Instruction also requires that safety-related items pass through receipt inspection. Included in such inspection, where applicable, is verification that material is in accordance with procurement documents, specifications, etc. Accepted material is identified with a green tag or similar device and either placed in segregated stores, or installed. Applicable Administrative Directives require that only correctly identified items may be put into operation.

The above material controls and revised drawing controls provide additional assurance that material misidentifications will be avoided in the future. In addition augmented training and re-training of personnel will be conducted to further reduce the likelihood of installation and use of unspecified material.

RESPONSE TO DEVIATION

The Indian Point 2 locations that contain sump pumps without lower guide rods are as follows:

1. De-icing Pit
2. Turbine Room Condenser Pit
3. Service Water Valve Pit
4. Intake Structure Service Water Pit
5. Turbine Room Condensate Pump Pit

Con Edison has consulted with the manufacturer of these pumps, the Barrett, Haentjens Company, of Hazelton, Pennsylvania. A representative of that firm advised that only upper guides are required when the unsupported rod length between the upper guide and the float is five (5) feet or less.

Since even the sumps in the above locations are three (3) feet or less in depth, the unsupported rod length is well within the manufacturer's five (5) foot length criteria. Therefore, continued operation of these pumps without lower guide rods is justified.

Arthur Hauspurg
President

Consolidated Edison Company of New York, Inc.
4 Irving Place, New York, N Y 10003
Telephone (212) 460-3726

March 26, 1981

Mr. Victor Stello, Jr., Director
Office of Inspection and Enforcement
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Stello:

Re: Indian Point Unit 2
Docket No. 50-247

We have your letter of March 2, 1981 and the accompanying order, signed by you for the Nuclear Regulatory Commission, imposing civil penalties on Con Edison in the amount of $210,000 for alleged noncompliance with NRC requirements. The order, in effect, rejects each and every explanation and contention in our eighty page reply to your initial notice of violation. No mitigation whatsoever of the penalty assessment is allowed despite the evidence in our reply showing that the allegations of noncompliance to which we object are erroneous.

The order advises us that we may contest the imposition of the penalty by either addressing a request to the Commission for a hearing or defending a collection suit by the Attorney General pursuant to the provision for such a suit in the Atomic Energy Act. We have carefully considered these alternatives and have concluded to pursue the latter.

We believe that a trial on the merits in a United States District Court will be the most economical and expeditious means of disposing of the penalty assessment and will be in the best interests of all concerned. A hearing before the Commission would likely result in an appeal to the courts in any event so resort to the courts in the first instance should shorten the procedure.

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We regret the need for litigation but we cannot accept the complete rejection of our views and the imposition of an unwarranted penalty. Notwithstanding our disagreement on penalties, we are expeditiously moving forward with actions to prevent recurrence and to continue our record of safe operation of nuclear power plants at Indian Point.

Very truly yours,

cc: Mr. Samuel J. Chilk, Secretary to the Commission
Mr. Boyce H. Grier, Director Region I
Mr. Theodore Rebelowski, Resident Inspector

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

MAR 0 2 1981

Docket No. 50-247
EA 81-11

Consolidated Edison Company of New York, Inc.
ATTN: Mr. Arthur Hauspurg
President
4 Irving Place
New York, New York 10003

Gentlemen:

This is in response to Consolidated Edison's letters of January 5 and February 11, 1981, which replied to our letter of December 11, 1980, transmitting a Notice of Violation and Proposed Imposition of Civil Penalty in the amount of $210,000.

Our letter of December 4, 1980 described the detailed results of our investigation undertaken after the October 17, 1980 containment flooding incident. Our letter of December 11, 1980 discussed the overall impact of inadequacies discovered as a result of the investigation. These inadequacies were the basis for the statement that the management control system at Indian Point Unit 2 was not functioning in an acceptable manner.

In your January 5, 1981 response to our letter of December 11, 1980, you contend that there was no failure of your management control system, partly based on the findings of an NRC special inspection (Inspection Report 50-247/80-11) of your utility management performed on three days in July and August of 1980. Although this inspection did not identify any noncompliances or significant concerns in the areas inspected, it was not an all encompassing inspection of your overall management control system. Specifically, the special inspection did not address your management control system for the areas of reporting, maintenance, surveillance, quality assurance, and the shift technical advisors (except for the STA training program status and schedule). The majority of the violations were found in the areas not covered by the special inspection. Additionally, an acceptable finding related to a particular area does not ensure that future concerns or noncompliances will not develop.

Your responses to the Notice of Violation provided additional details about the violations and the flooding incident in general. However, our belief that your management control system was inadequate has not changed. Your letter summarized differences of view that Consolidated Edison has with respect to the NRC findings and also took issue with our application of the regulations and the Interim Enforcement Policy published in the Federal Register on October 7, 1980. The enclosure to your letter further detailed your findings and opinions. We have evaluated and considered your responses, but have

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concluded that no basis for mitigation exists. Accordingly, we hereby serve the enclosed Order on Consolidated Edison Company of New York, Inc., imposing Civil Penalties in the amount of Two Hundred Ten Thousand Dollars ($210,000). Appendix A to this Order contains our detailed evaluation of your response and states our conclusion regarding each violation and deviation.

Appendix A to the Order enclosed with this letter also requests that supplemental responses for items II.A, II.B, II.C, II.D, II.F and the Deviation be provided to the NRC. This information is sought so that we may be assured that your corrective actions with respect to these items are adequate to prevent further similar violations. These responses should be in accordance with instructions contained in the December 11, 1980 Appendix A, Notice of Violation and Proposed Imposition of Civil Penalty. We are aware that information has been and continues to be supplied by you to various NRC offices as part of the ongoing activities at Indian Point. When submitting the requested additional information you may include by reference any information already formally provided to an NRC office.

Your January 5, 1981 response to our letter of December 11, 1980 had as an enclosure a report of your investigation into issues we identified as potential unreviewed safety questions. We have not completed our evaluation of your response to these items and they will be the subject of separate correspondence.

Notwithstanding the Civil Penalty imposed by the Order, we are pleased to note that you have committed to programmatic changes to improve your management control system and that you have reaffirmed your resolve for the safe operation of Indian Point, Unit 2.

In accordance with Section 2.790 of the NRC's "Rules of Practice," Part 2, Title 10, Code of Federal Regulations, a copy of this letter and its enclosure will be placed in the NRC's Public Document Room.

Sincerely,

Victor Stello, Jr.

Victor Stello, Jr.
Director
Office of Inspection
and Enforcement

Enclosure:
Order Imposing Civil Monetary
Penalties

cc w/encl:
L. O. Brooks, Project Manager, IP Nuclear
W. Monti, Manager, Nuclear Power Generation Department
M. Shatkouski, Plant Manager
J. M. Makepeace, Director, Technical Engineering
W. D. Hamlin, Assistant to Resident Manager (PASNY)
J. D. Block Esquire, Executive Vice President - Administration
Joyce P. Davis, Esquire
Brent L. Brandenburg, Assistant General Counsel

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, DC 20555

In the Matter of Consolidated Edison Company of New York, Inc. (Indian Point Nuclear Power Station, Unit 2)	))))))	Docket No. 50-247 EA 81-11

ORDER IMPOSING CIVIL MONETARY PENALTIES

I

The Consolidated Edison Company of New York, Inc.(the "licensee") is the holder of Operating License No. DPR-26 (the "license"), issued by the Nuclear Regulatory Commission (the "Commission"). The license authorizes operations of the Indian Point Nuclear Power Station, Unit 2 (the "facility"). The facility consists of a pressurized light water moderated and cooled reactor (PWR), located at the licensee's site in Buchanan, New York. The license was issued on October 19, 1971.

II

On October 17, 1980, the Indian Point Unit 2 Nuclear Power Plant experienced a flooding of the vapor containment. The Nuclear Regulatory Commission's Office of Inspection and Enforcement conducted an investigation of this incident during the period October 22 through November 21, 1980. The objectives of this investigation were: 1) to gather facts concerning the incident its cause, effect(s), and the licensee's response to the incident; and 2) to evaluate these facts as a basis for corrective or enforcement action, as appropriate. The investigation findings are stated in Investigation Report 50-247/80-19, December 4, 1980. As a result of this investigation, it appears the licensee has not conducted its activities in full compliance with the

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conditions of its license and the requirements of the Commission. A written Notice of Violation and Proposed Imposition of Civil Penalties was served upon the licensee by letter dated December 11, 1980, stating the nature of the items of noncompliance and the provisions of NRC requirements with which the licensee was in noncompliance and identifying the items of noncompliance for which civil penalties were imposed and the amount thereof. A letter dated January 5, 1981, with enclosures, in response to the Notice of Violation and Proposed Imposition of Civil Penalties, was received from the licensee. In addition, the licensee submitted additional information to the NRC in a letter dated February 11, 1981.

III

Upon consideration of Consolidated Edison's responses (January 5, 1981 and February 11, 1981) and the statements of fact, explanation and argument in denial or mitigation contained therein, as set forth in Appendix A to this order, the Director of the Office of Inspection and Enforcement has determined that the penalties proposed for the items of noncompliance designated in the Notice of Violation should be imposed.

IV

In view of the foregoing and pursuant to Section 234 of the Atomic Energy Act of 1954, as amended (42 U.S.C. 2282) and 10 CFR 2.205, IT IS HEREBY ORDERED THAT:

The licensee pay civil penalties in the total amount of Two Hundred Ten Thousand Dollars ($210,000) for Items IA, IIA, IIB, IIC, IID, IIE, IIIA and IIIB as set forth in Appendix A to this order (No civil penalties were assessed for Items IB, IIF, IV or for the deviation) within twenty-five (25) days of the date of this Order, by check, draft, or money order payable to the Treasurer of the United States and mailed to the Director of the Office of Inspection and Enforcement.

The licensee may, within twenty-five (25) days of the date of this Order, request a hearing. A request for a hearing shall be addressed to the Secretary to the Commission, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555. A copy of the hearing request shall also be sent to the Executive Legal Director, USNRC, Washington, D.C. 20555. If a hearing is requested, the Commission will issue an Order designating the time and place of hearing. Upon failure of the licensee to request a hearing within twenty-five (25) days of the date of this Order, the provisions of this Order shall be effective without further proceedings and, if payment has not been made by that time, the matter may be referred to the Attorney General for collection.

V

In the event the licensee requests a hearing as provided above, the issues to be considered at such a hearing shall be:

(a) whether the licensee was in noncompliance with the Commission's regulations and the conditions of the license for which civil penalties were imposed as set forth in the Notice of Violation referenced in Section II above; and

(b) whether on the basis of such items of noncompliance the Order should be sustained.

FOR THE NUCLEAR REGULATORY COMMISSION

Victor Stello, Jr., Director
Office of Inspection and Enforcement

Dated at Bethesda, Maryland
this 2nd day of March, 1981

Attachment:
Appendix A, Evaluations and Conclusions

APPENDIX A
EVALUATIONS AND CONCLUSIONS

For each item of noncompliance and associated civil penalty identified in the Notice of Violation (dated December 11, 1980), the original item of noncompliance is restated and the Office of Inspection and Enforcement's evaluation and conclusions regarding the licensee's responses to each item (dated January 5, and February 11, 1981) are presented.

Item I

The Commission regulations and the facility license require the licensee to report occurrences important to safety as indicated below:

Item I.A

Statement of Noncompliance

10 CFR 50.72(a), "Notification of significant events", requires that: "Each licensee of a nuclear power reactor, licensed under para. 50.21 or para. 50.22 shall notify the NRC Operations Center as soon as possible and in all cases within one hour by telephone of the occurrence of any of the following significant events and shall identify that event as being reported pursuant to this section:

(3) Any event that results in the nuclear power plant not being in a controlled or expected condition while operating or shutdown."

Contrary to the above, the following condition was not reported within one hour of identification:

The discovery on October 17, 1980 of unexpected conditions not specifically considered in the safety analysis report or technical specifications that required remedial action to prevent existence or development of an unsafe condition, specifically the existence of: a flooded reactor vessel pit, about four inches of river water on the vapor containment floor, and steam exiting the instrument thimble holes.

The containment flooding condition was found on October 17, 1980, but not reported to the NRC until October 20, 1980, which did not comply with the one hour reporting requirements of 10 CFR 50.72. Each day that the violation continued constitutes a separate violation for the purpose of computing the civil penalty.

This is a Severity Level III violation (Supplement I.C.2 of the Interim Enforcement Policy). Applying the civil penalty for each day that the violation continued results in a civil penalty of - $120,000.

Evaluation of Licensee Response

The licensee has argued that the standards by which the NRC considers a facility to be in an "unexpected" or "uncontrolled" condition are undefined by 10 CFR 50.72. In the licensee's view, it never considered the facility to be in an "unexpected" or "uncontrolled" condition and therefore, it did not consider the presence of water on the containment floor to be reportable to the NRC. Nevertheless, the licensee has conceded that it has violated 10 CFR 50.72 of the Commission's regulations. The licensee stated in its response of January 5, 1981 that:

> "Although the accumulation of water on the containment floor is to be expected, the actual amount of water discovered in the containment by plant personnel on October 17, 1980 did nonetheless represent, in the language of the regulation, an 'unexpected condition,' and in retrospect should have been promptly reported to the NRC. On this basis, we do not contest that a violation occurred as stated in paragraph I.A of the Notice of Violation, as the Office of Inspection and Enforcement has here interpreted 10 CFR 50.72."

The licensee contends, however, that the violation should be classified as Severity Level VI rather than Severity Level III and cites the vagueness of the regulation, the intent of the regulation as explained in Information Notice (IN) 80-06, the firm conviction of plant personnel that a "serious event" did not occur, and the contention that the flooding event had minor safety significance.

Despite its contention that the regulation is vague as to what must be reported to the NRC, the licensee has in fact conceded that the amount of water found on the containment floor was "unexpected" and therefore reportable under the meaning of the regulation.

Information Notice (IN) 80-06, issued on February 27, 1980 and a Supplement to IN 80-06, issued on July 29, 1980, both emphasize that "serious events that could result in an impact on the public health and safety" are the types of events that the NRC requires to be reported under 10 CFR 50.72. The wetting of the hot reactor vessel with cold river water had the potential of overstressing the reactor vessel, a condition that could cause vessel failure. The wetting of the stainless steel Incore Instrument Conduits with brackish river water had the potential for causing chloride stress corrosion and breeching of a component which is part of the Primary Coolant Pressure Boundary. The flooding of the Reactor Vessel Pit and Containment Floor had the potential for causing post-LOCA water levels to disable safety related equipment. The leaking Fan Cooler Units (FCUs), with faulty containment isolation valves, constituted a loss of Primary Containment Integrity. Each of these potential events could have resulted in a substantial safety hazard to the public. Hence this event does qualify for reporting under 10 CFR 50.72.

The fact that plant personnel erroneously concluded that the event was not potentially serious does not change the basic requirement to report the unexpected event. It should again be emphasized that the licensee has conceded that the amount of water on the containment floor was unexpected.

The licensee also maintains the event would not require an "open, continuous communication channel" with NRC as described in 50.72(b) and hence implies it need not be reported per 50.72(a). Had the licensee reported the event on 10/17/80, while water was still covering a portion of the Reactor Vessel, the

NRC would, in all likelihood, have required that an open continuous communication channel be maintained. Furthermore, the fact that the NRC may receive a 50.72(a) report and decide to not maintain an open continuous communications channel, in no way negates the requirement to make the report in the first place.

The licensee contends that the event which was not reported had minor safety significance. This contention is based on information not known and in some cases unavailable to the licensee at the time the decision to not report was made. That the licensee initially considered the event of more than minor safety significance is illustrated by the licensee's decision to shutdown the reactor on the morning of October 20, 1980. That subsequent analysis and inspection has indicated no significant damage has occurred from this event is indeed fortunate, but not sufficient justification for failure to report the unexpected condition, which at the time had unknown significance.

The licensee contends that failure to report this event should be considered a Severity Level VI violation and argues that the Notice of Violation does not explain "which serious safety mitigative or preventive system was unable to perform" its functions. The NRC Interim Enforcement Policy (45 FR at 66754) (October 7, 1980) states that the "severity level of a violation involving the failure to make a required report to the NRC will be based upon the significance of and the circumstances surrounding the matter not reported." The proposed enforcement policy also states that violations that are not specifically identified in the Supplements will be placed at the level best suited to the significance of the particular matter. The particular event not reported was considered significant and therefore placed at Severity Level III because of:

(1) the unreviewed safety question, which existed at the time, of operating a hot reactor vessel and stainless steel conduits in contact with cold brackish river water;

(2) the actual safety problems which existed, namely: loss of containment integrity, post-LOCA loss of at least one FCU, some post-LOCA boron dilution of recirculated water, and post-LOCA submergence and hence potential failure of safety related valves; and

(3) the potential safety problem which would have existed had flooding continued for a short additional period of time; namely post-LOCA submergence of the recirculation pump motors.

Finally, the licensee states that there is no "appropriate basis for accruing separate violations for each day of licensee misinterpretation." Under Section 234 of the Atomic Energy Act, as amended (42 USC 2282), the Commission is authorized to impose civil penalties for each day that a violation continues. The containment flooding condition was reportable to the NRC as of October 17, 1980 yet was not reported until October 20, 1980. Thus, the licensee violated the reporting requirement for three days (October 17, 18, and 19) and is, therefore, subject to a civil penalty for each day of the violation. Civil penalties for each day the violation continued are particularly appropriate in this case, because during each of the three days the incident was not reported, the licensee's management were alerted again and again to the existing situation, had the opportunity to report the occurrence and yet did not conclude that a report to the NRC should be made.

Conclusion

The item as stated is an item of noncompliance. The information provided in the licensee's response does not provide a basis for modification of the enforcement action or for remission or mitigation of the proposed penalty.

Item I.B

Statement of Noncompliance

Technical Specification 6.9.1.7.1 states, in part, that: "The types of events listed below shall be reported within 24 hours of identification...

c. Abnormal degradation discovered in...primary containment...."

Contrary to the above on October 17 and 18, 1980, leaks were discovered in several fan cooler units. These leaks constituted abnormal degradation of primary containment and were not reported to the NRC until October 20, 1980. This violates the 24 hour reporting requirement.

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III violation.

Evaluation of Licensee Response

The licensee contends that plant design features described in the FSAR to monitor and isolate the fan cooler units (FCUs) were operable on October 17 and 18, 1980, and that consequently, the requirements for containment integrity were satisfied. Thus, according to the licensee, no report pursuant to Technical Specification 6.9.1.7.1.c was required.

Although some of these features were operable, not all of them were. The outlet service water containment isolation valve for FCU #22 has been tested by the licensee and shown to be unable to hold pressure. The containment isolation valves for the other four FCUs were also tested and the licensee was unable to demonstrate their leak tight integrity. Thus primary containment integrity was clearly not maintained as evidenced by:

(1) multiple service water leaks inside containment in the piping and tubing to the FCUs;

(2) leaky containment isolation valves on the inlet and/or outlet service water lines for the FCUs; and

(3) service water system pressure to the FCUs in containment that is significantly below peak accident pressure in containment.

The licensee knew of the service water leaks on October 17, 1980 and was also aware of the status of the containment isolation valves, because personnel entering containment after the FCU service water valves were closed noted continued flow from the FCU condensate leak detection devices. Thus, upon identification of this abnormal degradation in primary containment, the licensee was required to report this fact to the NRC within 24 hours.

The licensee argues that prior to the flooding event at Indian Point 2 on October 17, 1980, service water leaks of the type experienced during this event were not considered reportable by the NRC. In support of this proposition, the licensee cites IE Bulletin 80-24 (November 21, 1980) and argues that the bulletin, as a result of the Indian Point 2 event, imposed the new requirement to report any service water system leaks within containment. The licensee argues that the NRC cannot apply this requirement retrospectively in order to sustain a violation against Consolidated Edison.

Despite this contention, IE Bulletin No. 80-24, "Prevention of Damage Due to Water Leakage Inside Containment (October 17, 1980, Indian Point 2 Event)," did not impose any new requirements but rather emphasized existing ones. Item 2.f of this Bulletin reemphasized the NRC's interest in receiving reports on degradation of primary containment. The NRC decided to emphasize in the Bulletin this already existing reporting requirement because at least one licensee (Consolidated Edison) had not considered it necessary to promptly report such leakage. This event should have been reported in accordance with technical specifications as described above, and is not a new requirement established in Bulletin 80-24 as the licensee contends.

The licensee contends that a separate violation for failure to report abnormal degradation in primary containment under Technical Specification 6.9.1.7.1.c is inappropriate, in light of the earlier cited violation for failure to report the plant in an unexpected condition under 10 CFR 50.72(a)(3). The licensee is required by TS 6.9.1.7.1 to report orally and in writing to the Director of Region I abnormal degradation in primary containment. The licensee is required by 10 CFR 50.72(a) and (b) to report orally to the NRC Operations Center the discovery of an event that results in the plant being in an unexpected condition and, until notified otherwise, to maintain a continuous communication channel to the NRC Operations Center. Thus, despite the licensee's contention, the licensee committed two acts of non-reporting and violated two separate reporting requirements. Even if the items to be reported had been the same, which they were not in this case, neither reporting requirement can be substituted for the other, since the chain and mode of communications is different for each of the requirements.

Finally, the licensee argues that this violation, as well as the violation described in Item I.A of the Notice of Violation dated December 11, 1980, cannot be classified as a Severity Level III because neither violation involved actual or high potential impact on the public. The justification for assigning Severity Level III to item I.A has been previously addressed. Item I.B. is associated with Item I.A in that together they indicate a problem with the licensee's lack of concern for NRC reporting requirements. Consequently, in accordance with footnote 17 of the Interim Enforcement Policy (45 FR at 66757), Item I.B has properly been assigned the same severity level as that of Item I.A.

Conclusion

The item as stated is a violation. The information provided in the licensee's response does not provide a basis for modification of the proposed enforcement action.

Item II

The station Technical Specifications and Quality Assurance Program prescribe the management controls designed to prevent or mitigate a serious safety event. A number of violations of management controls required in these documents occurred. The highest severity level associated with these violations is Severity Level III. Because you could reasonably have been expected to have taken effective measures to prevent this occurrence, civil penalties for these violations have been increased by 25%. Therefore a Civil Penalty - $50,000 is proposed. The civil penalty has been distributed to the separate violations as indicated below:

Item II.A

Statement of Noncompliance

Technical Specification 6.5.1.6 states in part that, "The Station Nuclear Safety Committee shall be responsible for:...

f. Review of facility operations to detect potential safety hazards...".

Contrary to the above, the Station Nuclear Safety Committee did not review, prior to a reactor startup on October 20, 1980, the potential safety hazards associated with the flooding event of October 17, 1980 during which the hot reactor vessel and various stainless steel components were wetted with cold, brackish river water.

This is a Severity Level III violation (Supplement I.C.2 of the Interim Enforcement Policy). Civil Penalty - $20,000.

Evaluation of Licensee Response

Although the licensee argues that "the accumulation of water on the containment floor was not considered a significant event from a safety standpoint requiring Station Nuclear Safety Committee review," it concedes that a Violation of Technical Specification 6.5.1.6 occurred. The licensee states:

"Even though there were no actual safety problems, and even though the Safety Committee was unaware of the vessel wetting at the time of this alleged violation, Consolidated Edison nonetheless agrees that the Committee should have reviewed all relevant safety considerations--however remote--after the discovery of substantial amounts of water inside containment and prior to reactor startup. We thus acknowledge that a violation occurred as set forth in paragraph II.A of the Notice of Violation."

The licensee does, however, dispute the severity level assigned to this violation. It argues that during the leakage event, there were no instances of actual or high potential impact on the public and that there was no deficiency in any "system" as that term is used in Supplement I.C.2 of the Interim Enforcement Policy.

Despite the licensee's contention that there was no actual or high potential impact on the public, there were potential safety problems in the following areas that could have had an impact on the public:

1. Degradation of service water piping and tubing creates the possibility of post-LOCA leakage from containment, particularly considering the approximately 15 psig service water pressure in the FCUs and a peak accident containment pressure of 47 psig. This was compounded by the excessive leak rates through the service water containment isolation valves. Also, if the leaking FCUs are isolated this renders them inoperable.

2. A LOCA coincident with the flooded containment would have submerged and made inoperable safety injection valves, as described by the licensee on page 11 of its response, thus reducing the redundancy and reliability of portions of the Safety Injection System.

3. Continued leakage after 10/17/80 would have further raised post-LOCA water levels, e.g.:

   125,000 gallons, Elev. 51'7-1/2"
   150,000 gallons, Elev. 51'11"

   The licensee depends on the next float level switch (in the recirculation sump) and subsequent operator action to prevent the flood from continuing. Both of these are subject to question since the operators did not react to the abnormal condition of a continuously actuated 51" level switch and apparently the 91" level switch did not actuate even though under water. Additionally, none of these switches had audible alarms, only white lights on a side panel in the control room. Thus, without early discovery, post-LOCA water levels could have easily reached 52'5", the bottom of the recirculation pump motors, or higher.

As to the licensee's contention that there was no deficiency in a "system", as that term is used in Supplement I.C.2 of the Interim Enforcement Policy, it should be emphasized that the term "system " is not restricted merely to hardware systems. Rather, "system" encompasses both hardware and management systems. In this instance, the violations for which the licensee was cited in Items II A-F represent violations of the licensee's Technical Specifications and Quality Assurance program. Both of these are management control systems that are by nature designed to prevent or mitigate serious safety events. As to the licensee's contention that isolated instances of personnel error have been characterized as a system breakdown, the large number of violations cited in Items II A-F emphasize that there were not "isolated instances" of errors, but rather a serious breakdown of the licensee's management control system.

The licensee also contends that it is inappropriate to increase the civil penalties assigned to the violations in Item II in that no basis is stated in the Notice of Violation for the NRC's finding that the licensee could reasonably have been expected to have taken effective preventive measures. In addition, the licensee contends that the Interim Enforcement Policy indicates that civil penalties will be increased by 25% only in cases "where the licensee disregards actual knowledge of a condition gained from prior NRC licensee audits and the like." The standard for increasing civil penalties by 25% is described in the Interim Enforcement Policy (45 FR at 66756) as when "the licensee could reasonably have been expected to have taken effective preventive measures." Thus, civil penalties can be increased by 25% any time the NRC determines the standard has been violated. Knowledge of a problem through various means of prior notice is just one example of the manner in which the standard can be violated. In this instance the NRC's basis for concluding that the licensee could reasonably have been expected to have taken effective measures to prevent the flooding incident is discussed in Investigation Report 50-247/80-19, paragraph 11, Meeting Report 50-247/80-19A, paragraph 2.c and is illustrated in Figures 4 and 6 of both reports. Specifically, the frequency of fan cooler unit leakage increased over the years and the licensee performed unqualified repairs of these leaks without adequate evaluation of their causes and took no particular care to ensure that systems were available or inspections performed to detect any failures or leaks that might develop. Thus, the licensee had prior notice of the potential for the flooding incident. Had proper attention been paid to these items upon their occurrence, it is reasonable to expect that the flooding incident could have been avoided.

The licensee also contends that violations based on a failure in its management control system should be dismissed because an IE inspection report dated September 2, 1980 indicated that licensee management had the proper regard for safe operation of the plant. However, the three day inspection conducted by the NRC was not all encompassing and in particular did not review management controls in the reporting, maintenance, surveillance and quality assurance areas, which constitute a significant portion of the areas identified above and cited in the Notice of Violation. Also, while no significant problems or noncompliances were found in the areas inspected in September 1980 this did not in any way grant the licensee immunity from subsequent adverse findings in these areas.

Corrective action commitments provided by the licensee are incomplete. It does not appear that items 1-4 of the licensee's response, if implemented prior to 10/17/80, would have resulted in a proper review of the facts by the SNSC prior to plant startup. A supplemental response is requested which will specify what additional changes and/or actions are planned to ensure that further similar violations will be avoided.

Conclusion

The item as stated is an item of noncompliance. The information provided by the licensee does not provide justification for modification of the enforcement action or for remission or mitigation of the proposed penalty.

Item II.B

Statement of Noncompliance

Technical Specification 6.8.1 requires that procedures shall be established, implemented and maintained to meet the requirements and recommendations of Appendix A to Regulatory Guide 1.33-1972, and ANSI N18.7-1972, sections 5.1 and 5.3.

1. Regulatory Guide 1.33-1972, Appendix A, paragraph H.1, calls for procedures of a type appropriate to the circumstances to assure that instruments and controls are properly calibrated and adjusted to maintain accuracy.

2. Regulatory Guide 1.33, Appendix A, paragraph H.2 calls for procedures to implement each surveillance test, inspection or calibration listed in the Technical Specifications. Technical Specification 3.1.F.1 requires a safety evaluation whenever reactor coolant system leakage is indicated by the means available.

3. ANSI N18.7-1972, Section 5.3, states that procedures shall provide an approved preplanned method of conducting operations. Section 5.3.2.6 states that limitations on parameters being controlled and appropriate corrective measures to return the parameter to the normal control band should be specified.

4. ANSI N18.7-1972, Section 5.1.6.1, states that maintenance or modifications that may affect functioning of safety related systems shall be performed to assure quality and that maintenance shall be properly preplanned and performed in accordance with written procedures appropriate to the circumstances.

Contrary to the above, procedures were not established, implemented and maintained in that, respectively:

1. No setpoints for containment sump pump operation were included in the surveillance test, PT-R2A, "Containment Sump Level Analog Test", Revision 2, which verified sump pump operability, and

2. Procedures were not established or implemented for the condensate flow leak detection system or the containment humidity detectors which would satisfactorily implement Technical Specification 3.1.F.1 to detect reactor coolant system leakage; and

3. Procedures were not established which would provide for a preplanned method of controlling the containment sump level. Specifically, no control band or maximum sump level was specified, nor were corrective measures detailed; and

4. Site administrative procedures were not established, implemented and maintained to provide guidance as to when written approved procedures were required for maintenance activities or as to when maintenance activities would constitute a modification, both of which require review and concurrence by the Station Nuclear Safety Committee.

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III. Civil Penalty - $10,000.

Evaluation of Licensee Response

Paragraph II.B.1 and 3:

The licensee contends that "ANSI N18.7-1972 states in Section 1 that the requirements of this Standard apply to all activities affecting the safety-related functions of nuclear power plant structures, systems, and components." This statement is found in ANSI N18.7-1976, but not in the 1972 edition, which is pertinent here. The licensee further states that the containment sump pumps are not defined as safety-related and uses this to justify its lack of procedural coverage for those pumps. Technical Specification (TS) 6.8.1 calls for procedures in accordance with Regulatory Guide 1.33-1972 (RG 1.33-1972) and ANSI 18.7-1972, and not just for "safety-related" components. There are many important components and systems listed in these documents which require written approved procedures and that are not defined as "safety-related" by licensee Quality Assurance Programs. RG 1.33-72, Appendix A, paragraph G.1.a calls for procedures for Liquid Radwaste Collection Systems. This would include the Containment Sump and Sump Pumps. ANSI N18.7-1972 and paragraph H.1 of RG 1.33-72 give some of the types of items that these procedures should contain; this is what the licensee's procedures lacked in Items II.B.1 and II.B.3.

Relative to item II.B.1 the licensee states that appropriate procedures did exist for the sump pumps in that float settings for starting and stopping the pumps were set so as not to allow the level in the sump to reach the 46' elevation and that the absence of a float setpoint procedure did not contribute to the flooding. The intent to keep the level in the sump from the 46' elevation clearly was not met, since prior to 10/17/80 the 46' elevation was flooded. The lack of a float setpoint calibration value in the procedure contributed to this flooding by allowing the turn-on point for the sump pumps to be above the last sump level light (i.e. the 51" light) which could provide warning before the 46' elevation was flooded.

With respect to paragraph II.B.3, the licensee contends that a procedure was established to provide a pre-planned method of controlling the containment sump level. The licensee argues that level control switch settings were physically preset and that licensee procedure PI-R2A was implemented to verify operability. Contrary to this implication, procedure PT-R2A is inadequate in that it does not specify any setpoints for pump operation.

The licensee also contends that the item of noncompliance is improperly assigned a Severity Level III because the item does not contain a violation which involves actual or high potential impact on the public and because the violations described in Item II.B are not in any way related to the violations contained in Item II.A. In Item II.A the licensee was assessed a civil penalty for its failure to have the Station Nuclear Safety Committee review potential safety hazards associated with the flooding incident prior to restarting the facility. The potential safety significance of the violation contained in Item II.A, and thus the justification for classifying the item as a Severity Level III violation, has been previously discussed. Item II.B. is associated with Item II.A. in that both constitute examples of the breakdown in the licensee's management control system. Accordingly, Item II.B., like all the violations contained in Items II.B-F, is assigned the same severity level as that assigned to Item II.A pursuant to footnote 17 of the Interim Enforcement Policy (45 FR at 66756). The licensee has misinterpreted footnote 17 to mean that each violation in a series of items must be causally connected to the first violation in that series. The correct view is that each violation in a series of items must all relate to the same "event" or "problem" before they can be assigned the same severity levels pursuant to footnote 17. In this instance, the "problem" identified in Items II A-F, is the licensee's breakdown in the management control system. Throughout its response to Items II A-F, the licensee has made the same arguments pertaining to the assigned severity levels for each item of noncompliance. The above discussion with respect to severity levels is applicable to each of these items and accordingly will not be repeated under each item.

Paragraph II.B.2:

Technical Specification (TS) 3.1.F.1 requires the licensee to conduct a safety evaluation within four hours of identification of reactor coolant system leakage. The methods used by the licensee to indicate such leakage are two systems of different principles, one of which is sensitive to radioactivity. The other system consists of humidity detectors and a condensate flow leak detection system. The licensee contends that its procedure SOP 1.7 adequately implements the TS applicable to reactor coolant system (RCS) leakage with regard to its dew point and fan cooler unit (FCU) flow monitoring systems. The NRC considers the procedures inadequate to implement the Technical Specifications as described in the Notice of Violation with respect to the FCU condensate leak detection system in that:

(a) Procedure SOP 1.7 has no required action level for weir water level;

(b) Procedure SOP 1.7 does suggest a water level of 2" and increasing in a weir as an action level, but this water level could correspond to an already significant RCS leak (between 7 and 14 gpm) and this suggested level was not used when exceeded (e.g., September 1980 data);

(c) The maximum water level limit of 4" identified in the control room log and the actual alarm setpoint of approximately 4" correspond to an already significant RCS leakage (greater than 14 gpm);

(d) No calibration procedures were established to calibrate or set the high level alarms for the FCU weir level detectors; and,

(e) In SOP 1.7, when evaluating weir levels, it was not clear what to use for initial values (step 4.1.A) or final values (step 4.1.B). Usually baseline data from October 25, 1979 were used, but not always. When these data were used, due to the length of time since established, it provided a baseline of questionable usefulness.

The procedures are inadequate with respect to the dew point system in that:

(a) The Procedure SOP 1.7 action level for dewpoint of 89°F and increasing and the control room log sheet's maximum dewpoint of 95°F, combined with a normal reading of 70°F or lower, corresponded to an already significant RCS leakage (greater than 4 gpm per NRC calculations).

(b) The humidity detectors were not sensitive to incremental increases of water leakage as described in the FSAR and TS Bases, because they were normally off scale low (less than 70°F) as shown in the control room logs for the majority of September 1980;

(c) No calibration procedures were established to calibrate or set the alarms for the humidity detectors; and,

(d) Graph RCS-8, which is used to quantitatively determine an RCS leak rate based on observed dewpoints, is not accurate since it apparently assumes a baseline dewpoint near 85°F, while actual baseline values are at or below 70°F.

The licensee's "Planned Actions to Modify Maintenance and Surveillance Program" does not address the specific inadequacies of Item II.B.2 as detailed above. A supplemental response is requested which specifies how RCS leak detection procedures and equipment will be upgraded to address Item II.B.2.

Paragraph II.B.4

The licensee contends that its site administrative procedures were adequate to provide guidance as to when written approved procedures were required for maintenance activities and when maintenance activities would constitute a modification, both of which require review and concurrence of the Station Nuclear Safety Committee (SNSC). The NRC considers these procedures inadequate. The licensee's maintenance practices onsite are performed using either an investigative checklist, a steplist or a maintenance procedure. Each of these is more formalized than the preceding one; each can be used on safety-related equipment; yet, only the maintenance procedure receives SNSC review and approval. ANSI N18.7-1972, paragraph 5.1.6.1 allows maintenance to be performed without a step by step written procedure where the skills required are possessed by qualified maintenance personnel. MAD-4, Rev. 1, as the licensee states, does give some examples of skills normally possessed by maintenance personnel. The examples given can be categorized as either troubleshooting or replacement of various parts in kind. However, maintenance activities other than troubleshooting or replacement in kind are performed using the steplists and checklists, such as the epoxy repairs to the FCUs. The licensee's administrative controls do not define when it is appropriate, for these types of circumstances, to perform the maintenance without written approved procedures.

Additionally, although the licensee's procedures require SNSC review of modifications, the administrative procedures established do not detail when a maintenance activity is to be considered a repair and when it is to be considered a modification. The licensee's response discusses the general guidance given in Site Administrative Directives but does not indicate that any specific guidance of the type discussed above exists.

The licensee's commitments for corrective action are incomplete. A supplemental response is requested which should indicate what corrective action will be taken to provide detailed guidance as to when written approved procedures are required for maintenance activities and as to when a maintenance activity constitutes a modification.

Conclusion

The item as stated is an item of noncompliance. The information provided by the licensee does not provide a basis for modification of the enforcement action or for remission or mitigation of the proposed penalty.

Item II.C

Statement of Noncompliance

10 CFR 50, Appendix B, Criterion II requires that:

> "...The quality assurance program shall provide control over activities affecting the quality of the identified...systems, and components...."

FSAR Volume A, Attachment A-2, "Quality Assurance Program (ANSI N18.7 Format) Revised June, 1977," Foreward, states that:

> "The following quality assurance program conforms to the requirements of 10 CFR 50, Appendix B. Additionally, Con Edison commits to have a Quality Assurance Program satisfying the requirements and guidelines of the following ANSI Standards and complying with the regulatory position in the Regulatory Guides as modified by Table A and Table B.

ANSI Standards

ANSI N18.7-1976 'Administrative Control and Quality Assurance for Operational Phase of Nuclear Power Plants.'"

ANSI N18.7, Paragraph 5.2.7.1, "Maintenance Programs" states that "The causes of malfunctions shall be promptly determined, evaluated and recorded...."

Contrary to the above, despite continued malfunctions (i.e., leaks) in the fan cooler units between 1973 and October 1980, the causes of the malfunctions had not been determined or recorded, and evaluations of the causes had not been completed.

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III Violation. Civil Penalty - $10,000.

Evaluation of Licensee Response

The licensee denies this violation although admitting that the evaluation of the cause of the leaks had not been completed. The licensee's contention is based in part on a documented evaluation performed in 1973 on the original FCU motor cooler heat exchangers (HXs) that developed leaks in brazed joints and were destructively examined. The licensee maintains that since the main FCU HXs are similar in design and fabrication to the motor cooler HXs, the main FCU HXs would be expected to fail in the same manner. Hence, the licensee indicates that he understood the failure mechanisms at work in the main FCU HXs and had no need to perform and record evaluations beyond the 1973 document. The investigation did not support this conclusion. During the time period 10/23/80 through 12/3/80, despite repeated requests by the investigation team of licensee personnel responsible for the design, performance and maintenance of the FCUs, the licensee was unable even to remember, much less provide, documentation of the 1973 failure analysis. Hence the use of the 1973 information and its significance in any decisions made by the licensee prior to the flooding event cannot be supported. Nevertheless the licensee never confirmed that the failure mechanism for the main FCU HXs brazed joints was in fact the same as that of the previously analyzed motor cooler HXs. Additionally, the licensee never evaluated the causes of the mid-tube failures on FCU #25. Finally the licensee's statement that all leaks were "promptly identified and corrected" is not accurate in that the estimated 10 gpm leak discovered on 10/17/80 was not identified and corrected until at least 110,000 gallons of water had accumulated on the Vapor Containment floor. Further, the temporary repairs and pipe clamps utilized over the years cannot be viewed as "correction" of the problem.

The licensee's proposed corrective action is unacceptable in that the licensee does not specify how and by whom the requirements of ANSI N18.7

to promptly determine, evaluate and record the causes of malfunctions will be accomplished. A supplemental response is requested to provide this information.

Conclusion

Item II.C, as stated, is an item of noncompliance. The information provided by the licensee does not provide a basis for modification of the enforcement action or for remission or mitigation of the proposed penalty.

Item II.D

Statement of Noncompliance

10 CFR 50, Appendix B, Criterion II, states"...The quality assurance program shall provide control over activities affecting the quality of the identified... systems, and components..."

FSAR Volume A, Attachment A-2, "Quality Assurance Program (ANSI N18.7 Format) Revised June 1977", Foreward, states "The following quality assurance program conforms to the requirements of 10 CFR 50, Appendix B. Additionally, Con Edison commits to have a Quality Assurance Program satisfying the requirements and guidelines of the following ANSI Standards...

ANSI Standards

ANSI N18.7-1976 'Administrative Control and Quality Assurance for the Operational Phase of Nuclear Power Plants'."

ANSI 1976, Paragraph 5.2.7.1, Maintenance Programs, tates in part, "A maintenance program shall be developed to maintain safety related...systems...at the quality required for them to perform their intended functions...Planning for maintenance shall include evaluation of the use of...materials in the performance of the task...".

10 CFR 50.59(b) states, in part, that the licensee shall maintain records of changes in the facility which include a written safety evaluation that provides the bases for the determination that a change does not involve an unreviewed safety question.

Technical Specification 6.5.1.6 requires that "The Station Nuclear Safety Committee (SNSC) shall be responsible for:...

d. Review of all proposed changes or modifications to plant systems or equipment that affect nuclear safety..."

Contrary to the above, modifications were made to the fan cooler unit cooling coils and service water lines during maintenance performed between 1978 and July, 1979 without review by the SNSC and without an evaluation being conducted to demonstrate that an unreviewed safety question was not involved or to demonstrate the suitability of epoxy sealant material to perform its intended function under loss of coolant accident (LOCA) conditions. In August, 1979 an evaluation of the epoxy sealant material was made, which did not consider all of the post-LOCA conditions or the specific mode in which the sealant was used. Subsequent to this, the plant was operated at power and additional repairs were made on July 7 and 25, 1980 and on October 3, 18 and 19, 1980.

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III Violation. Civil Penalty - $5,000.

Evaluation of Licensee Response

The licensee indicates that the epoxy fixes performed on the Fan Cooler Units (FCUs) were "repairs", not modifications, which returned the equipment to its original leak tight condition without changing its safety function. The licensee has identified a number of historical documents which could, when taken together, appear to provide an adequate basis for the use of epoxy under controlled application conditions. The licensee did not state or otherwise demonstrate that licensee personnel had reviewed and evaluated the cited documents to determine the acceptability of the techniques used prior to applying epoxy to correct tube leaks.

The substitution of epoxy-bonded tube-to-header joints for brazed joints and the use of epoxy as pressure retaining fixes for leaky tubes is considered to be a modification because it changes or alters the basic joint and tube design, rather than merely repairing the component to its original design. As such, the modification should have received proper review by the SNSC for its suitability and an evaluation by the licensee to determine if an unreviewed safety question was involved. Documents reviewed by the investigation team do not demonstrate that the licensee had reviewed or evaluated available documents prior to use of epoxy. The fact that the licensee has subsequently identified documents which support the use of epoxy or that the licensee, after the incident, performed tests to qualify its use, does not excuse the licensee from the requirement to perform an evaluation of the materials to be used and the changes to be made. In 1979 the licensee's first documented evaluation of the suitability of the epoxy (ESR No. I2-9019) concluded that "epoxy will not perform satisfactorily under certain application and operating procedures, and should therefore not be considered for use as a permanent repair."

The licensee also stated that a temporary repair was capable of 1 to 3 years satisfactory service, as documented in paragraph II.f.(4) of the investigation report. It should be noted that in 1979 some of the epoxy modifications were already over 3 years old and that the basis for allowing an unsatisfactory use of epoxy to exist, even for 3 years, is unclear. Additionally, the NRC does not believe that a good method exists to verify the acceptability of epoxy to determine its margin of safety or operational life. None of the test results cited by the licensee document the lifetime of an epoxy modification. This is particularly important considering the adverse conditions under which the modifications were sometimes made (reactor at power, ambient temperature around 120°F and maintenance personnel in respirators). Finally, contrary to the licensee's claim that no epoxy "repair" ever failed in service, MWR 25-2057, dated July 7, 1980 indicates that at least one application of epoxy to a cooling coil leak failed in service.

The licensee's proposed preventive action consists of general statements about new programs and as such could very well be acceptable and provide good controls for evaluating repairs, materials, changes and modifications. However, to properly evaluate the adequacy of the new programs with respect to the violation more information is needed. A supplemental response detailing the licensee's new program for evaluating repairs, materials, changes and modifications is requested.

Conclusion

The item as stated is a violation. The information provided by the licensee does not provide a basis for modification of the enforcement action or for remission or mitigation of the proposed penalty.

Item II.E

Statement of Noncompliance

10 CFR 50, Appendix B, Criterion XVI requires that "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected."

FSAR Volume A, Attachment A-2, "Quality Assurance Program (ANSI N18.7 Format) Revised June, 1977", Section 5.2.11, "Corrective Actions", states "Measures have been established which ensure that conditions adverse to plant safety which may occur during work, e.g. maintenance, are promptly identified in a Quality Control Inspection Report (QCIR) or a Deficiency Report (DR) and corrected...The action addressee on the Quality Control Inspection Report (QCIR)...is responsible for either correcting the nonconformance or designating the organization responsible for completing the necessary corrective actions. The managements of these designated organizations are responsible for taking the necessary corrective actions." Implementing Procedure SAO-113, Quality Control Reports and Stop Work Authority, Revisions 0 and 1, Paragraph 2.7, states in part, "In any case where the recipient of a QCIR is unable to make a schedule...or does not agree with the specific action called for, he will so inform the...QA Engineer in writing. Feedback to the QA Engineer per the requirements above should be provided promptly, i.e., generally within three (3) working days of the QCIR receipt."

Contrary to the above, the measures established did not assure prompt correction in that:

1. The following QCIRs had not been responded to promptly as no response has been received as of October 29, 1980.

    -- 79-2-14, issued April 2, 1979
    -- 79-2-27, issued May 27, 1979
    -- 79-2-43, issued July 17, 1979

-- 79-2-44, issued July 20, 1979
-- 79-2-74, issued September 17, 1979
-- 80-2-17, issued February 16, 1980
-- 80-2-19, issued March 17, 1980
-- 80-2-33, issued September 4, 1980

2. The following QCIRs were closed by the Quality Assurance Engineer based on various types of followup action but had never been responded to in writing.

-- 78-2-27, issued February 23, 1978
-- 79-2-66, issued August 27, 1979
-- 79-2-77, issued November 29, 1979
-- 79-2-75, issued September 20, 1979
-- 80-2-13, issued February 14, 1980
-- 80-2-28, issued July 25, 1980
-- 80-2-29, issued July 25, 1980
-- 80-2-39, issued October 2, 1980

3. The following QCIRs which are closed had not been responded to promptly.

-- 73-2-184, issued November 15, 1973; responded to May 5, 1974
-- 76-2-001, issued January 19, 1976; responded to March 9, 1976
-- 77-2-89, issued June 9, 1977; responded to August 3, 1977
-- 80-2-25, issued May 13, 1980; responded to July 17, 1980

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III Violation. Civil Penalty - $5,000.

Evaluation of Licensee Response

The licensee denies this violation and argues that its procedures did not require a response to be filed within three days.

The violation was issued because the measures established to assure prompt correction were not effective (e.g. their QA Program requirements) and not merely because the three-day time limit had expired. The 10 CFR 50, Appendix B, Criteria XVI requirement is to establish measures to assure prompt identification and correction of conditions adverse to quality. The licensee did establish the written controls, but the evidence indicates that the measures were such that they did not assure prompt correction. The length of time involved in the examples given, particularly where no responses had been made and no corrective action accomplished or stipulated, was excessive. Further, the licensee's claim that some QCIRs were used only to track repairs ignores the fact that those QCIRs had designated an "Action Addressee."

The licensee's proposed corrective action is a general statement and as such appears to be acceptable. However, based on the lack of effectivensss of the previous written controls discussed herein, the NRC reserves full acceptance of the proposed corrective action until the implementing procedures can be reviewed and their effectiveness determined.

Conclusion

This item, as stated, is an item of noncompliance. The information provided by the licensee does not provide a basis for modification of the enforcement action or for remission or mitigation of the proposed penalty.

Item II.F

Statement of Noncompliance

10 CFR 50, Appendix B, Criterion VIII, "Identification and Control of Materials, Parts, and Components", states that:

> "Measures shall be established for the identification and control of materials, parts, and components, including partially fabricated assemblies. These measures shall assure that identification of the item is maintained by heat number, part number, serial number, or other appropriate means, either on the item or on records traceable to the item, as required throughout fabrication, erection, installation, and use of the item. These identification and control measures shall be designed to prevent the use of incorrect or defective material, parts, and components."

FSAR Volume A, Attachment A-2, "Quality Assurance Program (ANSI N18.7 Format) Revised June, 1977", Foreward, states that "The following quality assurance program conforms to the requirements of 10 CFR 50, Appendix B. Additionally, Con Edison commits to have a Quality Assurance Program satisfying the requirements and guidelines of the following ANSI Standards.

ANSI Standards

ANSI N18.7-1976 'Administrative Control and Quality Assurance for the Operational Phase of Nuclear Power Plants'."

ANSI N18.7-1976, paragraph 5.2.7 states that:

> "Maintenance or modifications which may affect functioning of safety-related structures, systems, or components shall be performed in a manner to ensure quality at least equivalent to that specified in original design bases...Maintenance or modification of equipment shall be preplanned and performed in accordance with written procedures, documented instructions or drawings appropriate to the circumstances which conform to applicable codes."

Contrary to the above, maintenance repairs on the fan cooler unit water heat exchanger flexible hoses were not conducted in a preplanned manner and did not provide for the control identification of materials in that: MWR 4156 and MWR 6508 completed in 1976 failed to identify the as installed flexible hoses as Inconel 625 per Addendum No. 1 (dated September 2, 1972) to Specification 9321-01-248-76, assumed the materials to be austenitic stainless steel, removed the center section of the existing hose leaving a short 2 inch stub section of the original hose and installed a stainless steel replacement. A P8 to P8, austenitic stainless steel welding procedure was utilized for the P8 to Inconel dissimilar metal joint. An austenitic stainless steel flexible hose was substituted for the Inconel 625 hose required by the design specification.

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III violation.

Evaluation of Licensee Response

The licensee has admitted the violation. It concedes that "since there was an incorrect material identification, there was a violation as set forth in paragraph II.F of the Notice of Violation." The licensee contests the severity level of the violation. The assignment of severity levels for items II.A-F has been discussed previously under the NRC's Evaluation of Licensee Response, Paragraph II.B.1 and 3.

The NRC further notes that this violation is an example of measures not ensuring adequate control and identification of materials. In its response the licensee has not described what allowed this particular misidentification or what will ensure proper control so that misidentifications will be avoided in the future. A supplemental response is needed to provide this information.

Conclusion

The item as stated is a violation. The information provided by the licensee does not provide a basis for modification of the enforcement action.

Item III

NRC's Confirmatory Order to Consolidated Edison Company of New York, Inc., dated February 11, 1980 ordered the licensee to establish and man the Shift Technical Advisor (STA) position within ninety days.

NRC's letter to All Operating Nuclear Power Plants, dated September 13, 1979, titled "Followup Actions Resulting From The NRC Staff Reviews Regarding The Three Mile Island Unit 2 Accident," stated that licensees should establish the Shift Technical Advisor position by January 1, 1980, and that "...in order to provide both perspective in assessment of plant conditons and dedication to the safety of the plant, this function (Accident Assessment Function) should have a clear measure of independence from duties associated with the commercial operation of the plant."

Item III.A

Statement of Noncompliance

NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," states: "...that additional technical and analytical capability, dedicated to concern for the safety of the plant, needs to be provided in the control room to support the diagnosis of off-normal events and to advise the shift supervisor on actions to terminate or mitigate the consequences of such events..."; that the position of Shift Technical Advisor (STA) be established to fulfill this function; and that "...when assigned as shift technical advisor, these personnel are to have no duties or responsibilities for manipulation of controls or command of operations."

During the investigation, from October 22, 1980 to November 21, 1980, the NRC interviewed STAs who performed duties during the period from 11:00 P.M. on October 16, 1980 to 07:00 A.M. on October 20, 1980. The STAs stated that, contrary to the above, they are not always called to the Control Room when problems are identified and that operations personnel utilize STAs for routine activities not involving engineering review or evaluation of plant safety, once the plant is shutdown.

Also, the STAs, on their shift, had not evaluated the propriety of a return to power when it occurred twice on October 17, 1980 and once on October 20, 1980, nor did they evaluate the potential significance of the degraded plant conditions involving leakage from the fan cooler units, wetting of the reactor vessel with cold brackish river water and steam exiting from the instrument thimble holes.

This is a Severity Level III violation (Supplement I.C.2 of the Interim Enforcement Policy) Civil Penalty - $30,000. The civil penalty of $40,000 for Severity Level III violation has been distributed between this item of noncompliance and the following one, both of which together comprise an event.

Evaluation of Licensee Response

The licensee, in denying this violation, argues that its procedures regarding the use of Shift Technical Advisors (STAs) are consistent with NRC requirements, that STAs are not required to be on duty during cold shutdown or refueling, and that the STAs on duty during the flooding incident performed adequately and in a manner "consistent with their specified functions and the extent to which they had completed their ongoing training program."

The licensee's Operational Administrative Directive, OAD-9, Rev. 3, establishes the Shift Technical Advisors (STAs) responsibilities, authorities, position guides and job descriptions. NRC's confirmatory order to the licensee, dated 2/11/80, requires the STA to be on shift at all times, regardless of plant mode. By letters to the licensee dated 9/13/79 and 10/30/79, NRC required that STAs be dedicated to concern for safety and have independence from duties associated with commercial operations of the plant, thereby avoiding distractions from their primary functions, those being to perform engineering evaluations and assessments of the safety of operations and operational experiences. Since paragraph 7.4.4 of OAD-9 assigns to the STA as a major job function and responsibility, the "...coordination of activities during major outages...," a duty not specifically dedicated to concern for safety and one associated with expediting commercial operations, OAD-9, Rev. 3, is not consistent with NRC requirements.

The licensee contends that "...the use of the STAs for other than their specified functions during cold shutdown outages is consistent with the intended use of the STA, as specified in NRC's own documents...." NRC's confirmatory order to the licensee, dated 2/11/80, requires the STA to be on shift at all times, regardless of plant mode. The implication that the plant was in cold shutdown for the period of violation, when the licensee used the STAs for other than their intended function, is false, since the plant was maintained in hot shutdown from 10/17/80 to 10/21/80.

Although the licensee argues that the STAs performed adequately during the period of the flooding incident, the NRC considers the actions of the STAs and the use of them by plant personnel to be unacceptable during this period. For example, the licensee contends that the STA is called to the Control Room when problems are identified that require his expertise. Contrary to the implication of the licensee's statements, the STA on shift the morning of 10/17/80 was not called to the Control Room upon discovery of a problem with nuclear instrumentation channel N42; this STA discovered the condition upon observing shift personnel evaluating the problem during one of his routine tours of plant areas.

The licensee also contends that STAs were aware of the accumulation of water on the containment floor, plant conditions, and future plans. As a result of interviews of individuals assigned as STAs from 1230 hours on 10/17/80 to 0700 hours on 10/20/80, the NRC determined that:

(1) All STAs were aware of fan cooler unit leaks and that service water had flowed to the vapor containment floor;

(2) Only the Chief Operations Engineer, when he acted as STA, was aware of the maximium extent of floor and reactor vessel pit flooding;

(3) Two STAs who were on shift while water was still in the reactor vessel pit, and thus should have been aware of this fact, did not learn of it until after their shifts; and,

(4) No STA was aware that the reactor vessel had been wetted.

The licensee did not directly respond to the NRC's allegation that STAs, on their shift, had not evaluated the propriety of a return to power when it occurred twice on 10/17/80 and once on 10/20/80. The licensee did acknowledge that "...the STA did not recognize the full range of possible effects of the water on reactor systems..."

The licensee contends paragraph III.A of the Notice of Violation is incompatible with the findings contained in NRC Region I Inspection Report 50-247/80-11, dated September 2, 1980. A reading of the text selected by the licensee to support his contention shows that those findings were related to the adequacy and scheduling of the STA training program. The violation for which the licensee was cited related to the use and performance of the STAs and not their training program. Further, a satisfactory evaluation in an area does not in any way grant the licensee immunity from future adverse findings in that area.

The licensee also contests the severity level assigned to this violation. The licensee argues that "deficiencies in the STA program...could not properly be considered Severity Level III, since there were no 'violations which involve actual or high potential impact on the public.' (45 FR at 66755)."

Supplement I.C.2 of the Interim Enforcement Policy, describes a Severity Level III violation as:

> "A system designed to prevent or mitigate a serious safety event not being able to perform its intended function under certain conditions...."

The STA position is an integral part of a system designed to prevent or mitigate the consequences of serious safety events. Personnel assigned to this position are expected to (1) prevent serious safety events by engineering review and evaluation of operating experience, plant conditions, and future plans; and, (2) mitigate the consequences of serious safety events by assessing accident conditions and providing advice for corrective actions to the shift supervisor. To minimize possible distractions from safety judgements and dedication to assurance of safety, a clear measure of independence from the demands for continued commercial operations is required for the individuals assigned STA duties.

The licensee's failure to require STAs to be called to the Control Room when problems were identified, and its failure to ensure that operations personnel did not use STAs for routine activities not involving engineering review or evaluation of plant safety, once the plant was shutdown, allowed the creation of conditions which prevented the STAs from performing their intended function of mitigating or preventing the consequences of serious safety events.

Conclusion

The item as stated is an item of noncompliance. The information provided in the licensee's response does not provide a basis for modification of the enforcement action or for remission or mitigation of the proposed penalty.

Item III.B

Statement of Noncompliance

NRC's letter to All Operating Nuclear Power Plants, dated October 30, 1979, titled "Discussion of Lessons Learned Short Term Requirements," provided additional clarification of these requirements, and stated "...it is not acceptable to assign a person, who is normally the immediate supervisor of the shift supervisor to STA (Shift Technical Advisory) duties...."

Contrary to the above, the Chief Operations Engineer, the immediate supervisor of the Senior Watch Supervisor, the licensee's equivalent title to a shift supervisor, was assigned to perform STA duties on the 7:00 AM to 3:00 PM shift of October 17, 1980.

This is a Severity Level III violation. (Supplement I.C.2 of the Interim Enforcement Policy) Civil Penalty - $10,000.

Evaluation of Licensee Response

The licensee concedes that a violation occurred. The licensee's response states:

> "...Consolidated Edison admits that this person, in fulfilling the STA function from 7:00 AM to 3:00 PM on October 17, 1980, was not supposed to be doing so according to an NRC letter dated October 30, 1979. We thus acknowledge that a violation is stated by Paragraph III.B of the Notice of Violation."

The licensee denies, however, that the item is a Severity Level III violation because there was "no safety significance, much less 'actual or high potential impact on the public,' resulting from this individual having served as STA on October 17...." The importance of the STA position to safety has been described under the NRC's Evaluation of Licensee Response to Item III.A and is incorporated here. In addition, the potential impact on safety that could have resulted from this violation is illustrated by the fact that the leaking Fan Cooler Units, the steam vapor exiting the nuclear instrument detector thimble hole, and the flooded Vapor Containment were first discovered on the 7:00 AM to 3:00 PM shift on 10/17/80, but the extent of the discovered problems and their potential safety consequences was not recognized. The Chief Operations Engineer (COE) was assigned as STA during this period, but continued to perform his normal duties.

Conclusion

The item as stated is an item of noncompliance. The information provided in the licensee's response does not provide a basis for modification of the enforcement action or for remission or mitigation of the proposed penalty.

Item IV

Statement of Noncompliance

Technical Specification 6.8.1 requires that: "Written procedures shall be established, implemented and maintained...". Procedure E-12, "Nuclear Instrument Malfunction", Rev. 3 dated 7/5/78, step C-4.1.3 requires as "Immediate Operator Action", if one channel fails, that reactor power level be reduced and maintained at 70% or below. Step C-5.5 of Procedure E-12 subsequently requires that all the nuclear bistables associated with the defective channel be tripped by removing the control power fuses.

Contrary to the above: On October 17, 1980, the licensee removed the control power fuses associated with the defective channel N42, with reactor power level at about 90%. This resulted in an automatic runback to less than 75% reactor power.

This is a Severity Level V Violation (Supplement I.E of the Interim Enforcement Policy).

Evaluation of Licensee Response

The licensee acknowledges that a violation is stated in paragraph IV of the Notice of Violation. The licensee maintains, however, that the violation should not be categorized as Severity Level V. Severity Level V violations are described in Supplement I.E to the Interim Enforcement Policy as "Other violations, such as failure to follow procedures, that have other than minor safety or environmental significance." (45 F.R. 66758). The example given in the supplement of failure to follow procedures is precisely what this violation is. Additionally, it is of more than minor safety significance. Arbitrary decisions by operators to omit steps in approved procedures negates the value of having such procedures for all significant matters and of having operators trained in these procedures. Further, the plant was required to respond to an unnecessary transient. The turbine runback transient resulted in a rapid reactor downpower transient, along with primary pressure and temperature increases.

Conclusion

The item as stated is an item of noncompliance. The information provided in the licensee's response does not provide a basis for modification of the proposed enforcement action.

Deviation

Statement of Deviation

Based on the results of an NRC investigation conducted during the period October 22, 1980 to November 21, 1980, it appears that one of your activities was not conducted in accordance with standard industry practice or manufacturer's recommendations as indicated below:

Contrary to standard industry practice and the manufacturer's Technical Manual, "Goulds Installation, Operation, and Maintenance Instructions for Vertical Sump Pumps, Models 3171, 3172, 3173, 3174", the containment sump pump float rods were not attached or guided at the bottom from October 17, 1980 through October 20, 1980. This contributed to sump pump inoperability during the containment flooding incident. Also, contrary to guidance on page 9 of the manufacturer's Technical Manual, the pumps were not prevented from running against a shutoff head on September 14, 1980 and September 15, 1980 and at various times from October 17, 1980 to October 19, 1980 when the pump discharge valves were shut and power to the pumps was not secured.

Evaluation of Licensee Response

The licensee denies that a deviation has occurred. The licensee states in his response that the containment sump pumps were originally installed with only a single upper guide and does not indicate if there was ever any modification to add a lower guide. The investigation team was informed, by Mr. C. Jackson of Con Ed by phone on 11/24/80 that a lower guide had existed but became dislodged at some time. Additionally, the manufacturer's technical manual for the pump series installed at Indian Point pictures both lower and upper guides on the float mechanisms. The licensee further states that there are eleven other sump pumps at the Indian Point Station which have no lower guides and maintains that this is not contrary to standard industry practice. Investigation team experience with common sump pumps is that they typically have upper and lower guides. This was verified by examining two series of vertical sump pumps with float rods and balls: Pedestal Sump Pumps, Model PM-3600, PB-3600 and PC-3600 by Flotec, Inc.; and Flood Guard Sump Pumps Model P30, P31 and P32 by All Power Machine and Manufacturing Company. Both series of pumps had upper and lower guides and both sets of instructions referred to installing the guides. Additionally a technical representative recommended by the Sump Pump Manufacturer's Association (S.P.M.A.) of Chicago, Ill. told the investigation team on 2/19/81 that most vertical sump pumps with float rod controllers have both upper and lower rod guides. Thus by failing to attach lower guides to the float mechanisms, the licensee has deviated from standard industry practice. The NRC further requests that the licensee specify which systems at its facility currently contain sump pumps without lower guides and justify continued operation in this manner.

The licensee further maintains that prior to this incident the pumps have operated satisfactorily since initial plant operation. Given the sketchy records maintained for the maintenance of these pumps by the licensee, it is not clear that trouble free operation can be supported nor the original status of the guides determined. With only a single guide for the float ball and rod, the potential exists for the rod becoming cocked. This could cause sticking as the rod passes through the sump grating as occurred during the incident. The fact that the sump pump would not operate due to the stuck float rod allowed the water to accumulate in containment and removed the primary means of detecting service water leaks into containment (i.e. Waste Holdup Tank inleakage calculations). Thus it appears that the licensee, in accordance with standard industry practice and the manufacturer's technical manual, should have provided and maintained an upper and lower guide for the float rod assembly.

The licensee has admitted that there is potential harm in running the sump pumps against a shutoff head and that the pump vendor recommends a minimum flow. In this case no damage actually occurred, as shown by examination of the pumps.

Conclusion

The item as stated is a deviation. The information presented by the licensee does not provide a basis for modification of the enforcement action.

John D. O'Toole
Assistant Vice President

Consolidated Edison Company of New York, Inc.
4 Irving Place, New York, N.Y. 10003
Telephone (212) [illegible]

Letter No. 81-28
February 11, 1981

Re: Indian Point Unit No. 2
Docket No. 50-247

Mr. Victor Stello, Jr., Director
Office of Inspection and Enforcement
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

SUBJECT: Consolidated Edison's Response to Notice of Violation and Proposed Imposition of Civil Penalty dated December 11, 1980

Dear Mr. Stello:

This letter relates to your letter of December 11, 1980, enclosing a Notice of Violation and Proposed Imposition of Civil Penalty resulting from your office's investigation of the October 1980 accumulation of service water inside containment at Indian Point Unit No. 2. Our response was sent to you on January 5, 1981, and the purpose of this letter is to supplement our response with detailed information relevant to your December 11 letter which has been confirmed with vendor sources.

Regarding the use of epoxy for maintenance of the fan cooler units as discussed at pp. 45-49 of our January 5 Statement, the effects of high energy radiation on Master Bond sealant were also tested at the High Energy Research Laboratory in Switzerland and at the Rutherford Laboratory in England. This work was part of a test program studying the radiation resistance of epoxies which began at these laboratories in 1969 and continued through 1979, and was in addition to the Radiation Dynamics testing which we referred to in our January 5 Statement. We are now advised by the manufacturer that this Radiation Dynamics testing occurred in 1976-77, rather than in 1973. Consolidated Edison's use of Master Bond in connection with the fan cooler units at Indian Point commenced in 1979. Thus prior to our initial use, radiation exposure testing at these laboratories qualified this epoxy for continuous service at greater than 281 degrees F, and 10^9 rads.

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Your December 11 letter and enclosures also contained a statement of alleged deviation regarding sump pumps, which asserted that the lack of a guide at the bottom of the Indian Point Unit No. 2 containment sump pump was contrary to standard industry practice. Our review does not confirm any such industry practice, and no source for this statement was set forth by your office. In fact, Indian Point Unit No. 2 has five Hazelton sump pumps, manufactured by Barrett, Haentzens & Co., which do not have lower guides. In addition, Indian Point Unit No. 1 has five Peerless sump pumps, manufactured by the FMC Corporation, which do not have lower guides. Indian Point Unit No. 1 also has a sump pump manufactured by Chicago Pump which does not have a lower guide. All of these pumps were installed in accordance with manufacturer's recommendations, which did not require installation of lower guides.

If you have any questions regarding the foregoing, please do not hesitate to call us. We trust that our earlier materials as supplemented herein will assist your office in reassessing the event and, we hope eventually reaching the same conclusions we did, as set forth in o… January 5 submissions.

Very truly yours,

John D. O'Toole

John D. O'Toole
Assistant Vice President

Subscribed and sworn to before
me this 11 day of February, 1981.

Notary Public

cc: Mr. Samuel J. Chilk
Mr. William J. Dircks
Mr. Boyce H. Grier
Mr. Theodore Rebelowski

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

Docket No. 50-247
EA 81-11

DEC 11 1980

Consolidated Edison Company of
New York, Inc.
ATTN: Mr. Arthur Hauspurg
President
4 Irving Place
New York, New York 10003

Gentlemen:

On October 17, 1980, th... operators at Indian Point Unit 2 discovered that leaks in a fan cooler unit had resulted in service water flooding of the reactor vessel pit and vapor containment floor. This further resulted in the wetting of the lower part of the hot reactor vessel by cold river water which contained a high concentration of chloride ions.

The matter was brought to our attention by your telephone notification to our Senior Resident Inspector on October 20, 1980. Based on a subsequent telephone conversation on October 21, 1980, as documented in our letter to you dated October 22, 1980, you agreed to make certain determinations regarding the causes of the occurrence, report these determinations to us, and obtain NRC concurrence prior to restart of Indian Point Unit 2. From October 22, 1980 to November 21, 1980, the NRC conducted an investigation of the circumstances surrounding this event. At a public meeting in White Plains, New York, on November 5, 1980, you stated that the plant would remain shutdown for correction of identified problems including replacement of the cooling coils for the five fan cooler units, until approximately June, 1981.

The results of our investigation, which include identification of violations which directly contributed to the flooding event, show that the management control system at Indian Point Unit 2 was not functioning in an acceptable manner Your failure to evaluate modifications to the service water piping by the long term use of epoxy materials, identify and correct the root cause of the numerous leaks in this system, identify the potential significance of the flooding on plant operations, evaluate the consequences of the flooding prior to reactor startup on October 20, 1980, and promptly report the flooding to the NRC, show that management at all levels is not directing the proper level of attention to operation of Indian Point Unit 2. Failure by management to identify and address the problems associated with these items is viewed as a serious matter.

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

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Further, our review of the circumstances surrounding the flooding event identified four unreviewed safety questions; ie, (1) partial submergence of the hot reactor vessel in cold brackish river water, (2) partial submergence of the stainless steel incore instrument conduits in brackish river water, (3) potential post-Loss of Coolant Accident (LOCA) water levels in containment in excess of the assumptions used in the Safety Analysis Report (SAR), and (4) potential post-LOCA water boron concentrations less than the assumptions used in the SAR. Your response to this letter should include a description of the results of your investigation and resolution of these issues, assuming (1) plant conditions discovered on October 17, 1980, and (2) plant conditions which could have developed, had the plant again been returned to power without discovery of the leakage and flooding problems.

We propose to impose civil penalties in the amount of $210,000 for the violations described in Appendix A. These violations have been categorized into the levels described in accordance with the Interim Enforcement Policy as published in Federal Register Notice (45 FR 66754) dated October 7, 1980. The history of fan cooler unit service water leaks at Indian Point Unit 2 indicates that additional occurrences of leakage should have been expected. Detection of these leaks required routine vapor containment inspection or maintaining the vapor containment sump pumps operable. Your failure to identify and correct the causes of leakage, to require routine vapor containment inspections, or to establish adequate controls to insure Sump Pump operability, led directly to the flooding event. Since management could reasonably have been expected to have taken effective corrective measures and did not, civil penalties have been increased by 25 percent above those listed in Table I of the Interim Enforcement Policy with respect to the violations enumerated in Section II of Appendix A.

Civil penalties have also been assessed for your failure to notify the NRC of the conditions associated with the flooding event within the time limits prescribed by law. Also, civil penalties have been assessed for violations with respect to the use of Shift Technical Advisors as outlined in Appendix A.

A Notice of Deviation is enclosed which describes the failure to maintain the containment sump pump floats in accordance with the manufacturer's instructions and periodic operation of the pumps with their discharge valves closed. The failure to maintain a proper guide for the lower float rod resulted in a malfunction of the float for one pump, an event which contributed to the flooding of containment.

Your response to this letter should emphasize and include a detailed description of plans and actions to improve your management control system.

Your written reply to this letter, combined with our evaluation of your response to questions previously requested of you regarding the flooding event, will be considered in determining whether any further enforcement action, such as modification, suspension, or revocation of your license, may be required to assure future compliance.

You are required to respond to this letter and in preparing your response, you should follow the instructions in Appendices A and B.

In accordance with Section 2.790 of the NRC's "Rules of Practice", Part 2, Titl 10, Code of Federal Regulations, a copy of this letter and the enclosures will be placed in the Commissioner's Public Document Room.

Sincerely,

Victor Stello, Jr.
Director
Office of Inspection
and Enforcement

Enclosures:
1. Appendix A - Notice of Violation and
   Proposed Imposition of Civil Penalty
2. Appendix B - Notice of Deviation

cc w/encls:
L. O. Brooks, Project Manager, IP Nuclear
W. Monti, Manager - Nuclear Power Generation Department
M. Shatkouski, Plant Manager
J. M. Makepeace, Director, Technical Engineering
W. D. Hamlin, Assistant to Resident Manager (PASNY)
J. D. Block, Esquire, Executive Vice President - Administration
Joyce P. Davis, Esquire
Brent L. Brandenburg, Assistant General Counsel

APPENDIX A

NOTICE OF VIOLATION AND PROPOSED IMPOSITION OF CIVIL PENALTY

Consolidated Edison Company
of New York, Inc
Indian Point 2

Docket No. 50-247
License No. DPR-26
EA 81-11

The NRC conducted an investigation into the flooding of containment at Indian Point 2 on October 22, 1980 through November 21, 1980. This investigation found that the management system, which is designed to prevent or mitigate a serious safety event, was not able to perform its intended function under the conditions preceding and during the containment flooding. As a result, the NRC proposes to impose a civil penalty in accordance with the Interim Enforcement Policy as published in the Federal Register October 7, 1980 (45 FR 66754). Pursuant to Section 234 of the Atomic Energy Act of 1954, as amended (42 USC 2282, P. L. 96-295), and 10 CFR 2.205 of the Commission's Regulations, in the amount set forth below for the following violations:

I. The Commission regulations and the facility license require the licensee to report occurrences important to safety as indicated below.

A. 10 CFR 50.72(a), "Notification of significant events", requires that:

"Each licensee of a nuclear power reactor, licensed under para. 50.21 or para. 50.22 shall notify the NRC Operations Center as soon as possible and in all cases within one hour by telephone of the occurrence of any of the following significant events and shall identify that event as being reported pursuant to this section:

(3) Any event that results in the nuclear power plant not being in a controlled or expected condition while operating or shutdown."

Contrary to the above, the following condition was not reported within one hour of identification:

The discovery on October 17, 1980 of unexpected conditions not specifically considered in the safety analysis report or technical specifications that required remedial action to prevent existence or development of an unsafe condition, specifically the existence of: a flooded reactor vessel pit, about four inches of river water on the vapor containment floor, and steam exiting the instrument thimble holes.

The containment flooding condition was found on October 17, 1980, but not reported to the NRC until October 20, 1980, which did not comply with the one hour reporting requirements of 10 CFR 50.72. Each day that the violation continued constitutes a separate violation for the purpose of computing the civil penalty.

This is a Severity Level III violation (Supplement I.C.2 of the Interim Enforcement Policy) Applying the civil penalty for each day that the violation continued results in a civil penalty of - $120,000.

B. Technical Specification 6.9.1.7.1 states, in part, that:

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"The types of events listed below shall be reported within 24 hours of identification...

c. Abnormal degradation discovered in...primary containment....

Contrary to the above on October 17 and 18, 1980, leaks were discovere in several fan cooler units. These leaks constituted abnormal degradation of primary containment and was not reported to the NRC until October 20, 1980. This violates the 24 hour reporting requirement.

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III violation.

II. The station Technical Specificat and Quality Assurance Program prescrib the management controls designed to prevent or mitigate a serious safety event. A number of violations of management controls required in these documents ocurred. The highest severity level associated with these violations is Severity Level III. Because you could reasonably have been expected to have taken effective measures to prevent this occurrence, civil penalties for these violations have been increased by 25%. Therefore a Civil Penalty - $50,000 is proposed. The civil penalty has been distributed to the separate violations as indicated below:

A. Technical Specification 6.5.1.6 states in part that, "The Station Nuclear Safety Committee shall be responsible for:...

f. Review of facility operations to detect potential safety hazards...".

Contrary to the above, the Station Nuclear Safety Committee did not review, prior to a reactor startup on October 20, 1980, the potential safety hazards associated with the flooding event of October 17, 1980 during which the hot reactor vessel and various stainless steel components were wetted with cold, brackish river water.

This is a Severity Level III violation (Supplement I.C.2 of the Interi Enforcement Policy). Civil Penalty - $20,000.

B. Technical Specification 6.8.1 requires that procedures shall be established, implemented and maintained to meet the requirements and recommendations of Appendix A to Regulatory Guide 1.33-1972, and ANSI N18.7-1972, sections 5.1 and 5.3.

1. Regulatory Guide 1.33-1972, Appendix A, paragraph H.1, calls for procedures of a type appropriate to the circumstances to assure that instruments and controls are properly calibrated and adjuste to maintain accuracy.

2. Regulatory Guide 1.33, Appendix A, paragraph H.2 calls for procedures to implement each surveillance test, inspection or calibrat listed in the Technical Specifications. Technical Specification 3.1.F.1 requires a safety evaluation whenever reactor coolant system leakage is indicated by the means available.

3. ANSI N18.7-1972, Section 5.3, states that procedures shall provide an approved preplanned method of conducting operations. Section 5.3.2.6 states that limitations on parameters being controlled and appropriate corrective measures to return the parameter to the normal control band should be specified.

4. ANSI N18.7-1972, Section 5.1.6.1, states that maintenance or modifications that may affect functioning of safety related systems shall be performed to assure quality and that maintenance shall be properly preplanned and performed in accordance with written procedures appropriate to the circumstances.

Contrary to the above, procedures were not established, implemented and maintained in that, respectively:

1. No setpoints for containment sump pump operation were included in the surveillance test, PT-R2A, "Containment Sump Level Analog Test", Revision 2, which verified sump pump operability; and

2. Procedures were not established or implemented for the condensate flow leak detection system or the containment humidity detectors which would satisfactorily implement Technical Specification 3.1.F.1 to detect reactor coolant system leakage; and,

3. Procedures were not established which would provide for a preplanned method of controlling the containment sump level. Specifically, no control band or maximum sump level was specified, nor were corrective measures detailed; and

4. Site administrative procedures were not established, implemented and maintained to provide guidance as to when written approved procedures were required for maintenance activities or as to when maintenance activities would constitute a modification, both of which require review and concurrence by the Station Nuclear Safety Committee.

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III. Civil Penalty - $10,000.

C. 10 CFR 50, Appendix B, Criterion II requires that:

"...The quality assurance program shall provide control over activities affecting the quality of the identified..systems, and components...".

FSAR Volume A, Attachment A-2, "Quality Assurance Program (ANSI N18.7 Format) Revised June, 1977", Foreward, states that:

"The following quality assurance program conforms to the requirements of 10 CFR 50, Appendix B. Additionally, Con Edison commits to have a Quality Assurance Program satisfying the requirements and guidelines of the following ANSI Standards and complying with the Regulatory Position in the Regulatory Guides as modified by Table A and Table B.

ANSI Standards

N18.7-1976 'Administrative Control and Quality Assurance for the Operational Phase of Nuclear Power Plants'

ANSI 18.7, Paragraph 5.2.7.1, "Maintenanc Programs" states that

"The causes of malfunctions shall be promptly determined, evaluated ar recorded...".

Contrary to the above, despite continued malfunctions (i.e., leaks) in the fan cooler units between 1973 and October 1980, the causes of the malfunctions had not been determined or recorded, and evaluations of the causes had not been completed.

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III Violation. Civil Penalty - $10,000.

D. 10 CFR 50, Appendix B, Criterion II, states "...The quality assurance program shall provide control over activities affecting the quality of the identified...systems, and components..."

FSAR Volume A, Attachment A-2, "Quality Assurance Program (ANSI N18.7 Format) Revised June, 1977", Foreword, states "The following quality assurance program conforms to the requirements of 10 CFR 50, Appendix Additionally, Con Edison commits to have a Quality Assurance Program satisfying the requirements and guidelines of the following ANSI Standards...

ANSI Standards

N18.7-1976 'Administrative Control and Quali urance for the Operational Phase of Nuclear Pow lants'."

ANSI 18.7-1976, Paragraph 5.2.7.1, Maintenance Programs, states in par "A maintenance program shall be developed to maintain safety related... systems...at the quality required for them to perform their intended functions...Planning for maintenance shall include evaluation of the use of...materials in the performance of the task...".

10 CFR 50.59(b) states, in part, that the licensee shall maintain records of changes in the facility which include a written safety evaluation that provides the bases for the determination that a change does not involve an unreviewed safety question.

Technical Specification 6.5.1.6 requires that "The Station Nuclear Safety Committee (SNSC) shall be responsible for: ...

d. Review of all proposed changes or modifications to plant systems of equipment that affect nuclear safety..."

Contrary to the above, modifications were made to the fan cooler unit cooling coils and service water lines during maintenance performed between 1973 and July, 1979 without review by the SNSC and without an evaluation being conducted to demonstrate that an unreviewed safety question was not involved or to demonstrate the suitability of epoxy sealant material to perform its intended function under loss of coolant accident (LOCA) conditions. In August, 1979 an evaluation of the epoxy sealant material was made, which did not consider all of the post-LOCA conditions or the specific mode in which the sealant was used. Subsequent to this, the plant was operated at power and additional repairs were made on July 7 and 25, 1980 and on October 3, 18 and 19, 1980.

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III Violation. Civil Penalty - $5,000.

E. 10 CFR 50, Appendix B, Criterion XVI requires that "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected."

FSAR Volume A, Attachment A-2, "Quality Assurance Program (ANSI N18.7 Format) Revised June, 1977", Section 5.2.11, "Corrective Actions", states "Measures have been established which ensure that conditions adverse to plant safety which may occur during work, e.g., maintenance, are promptly identified in a Quality Control Inspection Report (QCIR) or a Deficiency Report (DR) and corrected...The action addressee on the Quality Control Inspection Report (QCIR)...is responsible for either correcting the nonconformance or designating the organization responsible for completing the necessary corrective actions. The managements of these designated organizations are responsible for taking the necessary corrective actions." Implementing Procedure SAO-113, Quality Control Reports and Stop Work Authority, Revisions 0 and 1, Paragraph 2.7, states in part, "In any case where the recipient of a QCIR is unable to make a schedule...or does not agree with the specific action called for, he will so inform the ... QA Engineer in writing. Feedback to the QA Engineer per the requirements above should be provided promptly, i.e., generally within three (3) working days of the QCIR receipt."

Contrary to the above, the measures established did not assure prompt correction in that:

1. The following QCIRs had not been responded to promptly as no response has been received as of October 29, 1980.

   - 79-2-14, issued April 2, 1979
   - 79-2-27, issued May 27, 1979
   - 79-2-43, issued July 17, 1979
   - 79-2-44, issued July 20, 1979
   - 79-2-74, issued September 17, 1979
   - 80-2-17, issued February 16, 1980
   - 80-2-19, issued March 17, 1980
   - 80-2-33, issued September 4, 1980

2. The following QCIRs were closed by the Quality Assurance Engineer based on various types of followup action but had never been responded to in writing.

   -- 78-2-27, issued February 23, 1978
   -- 79-2-66, issued August 27, 1979
   -- 79-2-77, issued November 29, 1979
   -- 79-2-75, issued September 20, 1979
   -- 80-2-13, issued February 14, 1980
   -- 80-2-28, issued July 25, 1980
   -- 80-2-29, issued July 25, 1980
   -- 80-2-39, issued October 2, 1980

3. The following QCIRs which are closed had not been responded to promptly.

   -- 73-2-184, issued November 15, 1973; responded to May 5, 19[illegible]
   -- 76-2-001, issued January 19, 1976; responded to March 9, 1976
   -- 77-2-89, issued June 9, 1977; responded to August 3, 1977
   -- 80-2-25, issued May 13, 1980; responded to July 17, 1980

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III Violation. Civil Penalty - $5,000.

F. 10 CFR 50, Appendix B, Criterion VIII, "Identification and Control of Materials, Parts, and Components", states that:

"Measures shall be established for the identification and control of materials, parts, and components, including partially fabricated assemblies. These measures shall assure that identification of the item is maintained by heat number, part number, serial number, or other appropriate means, either on the item or on records traceable to the item, as required throughout fabrication, erection, installation, and use of the item. These identification and control measures shall be designed to prevent the use of incorrect or defective material, parts, and components."

FSAR Volume A, Attachment A-2, "Quality Assurance Program (ANSI N18.7 Format) Revised June, 1977", Foreword, states that "The following quality assurance program conforms to the requirements of 10 CFR 50, Appendix B. Additionally, Con Edison commits to have a Quality Assurance Program satisfying the requirements and guidelines of the following ANSI Standards...

<u>ANSI Standards</u>

N18.7-1976 'Administrative Control and Quality Assurance for the Operational Phase of Nuclear Power Plants'."

ANSI 18.7-1976, paragraph 5.2.7 states that:

"Maintenance or modifications which may affect functioning of safety-related structures, systems, or components shall be performed in a manner to ensure quality at least equivalent to that specified in original design bases ...Maintenance or modification of equipment shall be preplanned and performed in accordance with written procedures, documented instructions or drawings appropriate to the circumstances which conform to applicable codes."

Contrary to the above, maintenance repairs on the fan cooler unit water heat exchanger flexible hoses were not conducted in a preplanned manner and did not provide for the control and identification of materials in that: MWR 4156 and MWR 6508 completed in 1976 failed to identify the as installed flexible hoses as Inconel 625 per Addendum No. 1 (dated September 2, 1972) to Specification 9321-01-248-76, assumed the materials to be austenitic stainless steel, removed the center section of the existing hose leaving a short 2 inch stub section of the original hose and installed a stainless steel replacement. A P8 to P8, austenitic stainless steel welding procedure was utilized for the P8 to Inconel dissimilar metal joint. An austenitic stainless steel flexible hose was substituted for the Inconel 625 hose required by the design specification.

In accordance with Footnote 17 to Section B of the Interim Enforcement Policy this is categorized as a Severity Level III.

III. NRC's Confirmatory Order to Consolidated Edison Company of New York, Inc., dated February 11, 1980, ordered the licensee to establish and man the Shift Technical Advisor (STA) position within ninety days.

NRC's letter to All Operating Nuclear Power Plants, dated September 13, 1979, titled "Followup Actions Resulting From The NRC Staff Reviews Regarding The Three Mile Island Unit 2 Accident," stated that licensees should establish the Shift Technical Advisor position by January 1, 1980, and that "...in order to provide both perspective in assessment of plant conditions and dedication to the safety of the plant, this function (Accident Assessment Function) should have a clear measure of independence from duties associated with the commercial operation of the plant."

A. NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," states: "...that additional technical and analytical capability, dedicated to concern for the safety of the plant, needs to be provided in the control room to support the diagnosis of off-normal events and to advise the shift supervisor on actions to terminate or mitigate the consequences of such events..."; that the position of Shift Technical Advisor (STA) be established to fulfill this function; and that "...when assigned as shift technical advisor, these personnel are to have no duties or responsibilities for manipulation of controls or command of operations."

During the investigation, from October 22, 1980 to November 21, 1980, the NRC interviewed STAs who performed duties during the period from 11:00 PM on October 16, 1980 to 07:00 AM on October 20, 1980. The STA, stated that, contrary to the above, they are not always called to the Control Room when problems are identified and that operations personnel utilize STA's for routine activities not involving engineering review or evaluation of plant safety, once the plant is shut down.

Also the STAs, on their shift, had not evaluated the propriety of a return to power when it occurred twice on October 17, 1980 and once on October 20, 1980, nor did they evaluate the potential significance of the degraded plant conditions involving leakage from the fan cooler units, wetting of the reactor vessel with cold brackish river water and steam exiting from the instrument thimble holes.

This is a Severity Level III violation (Supplement 1.C.2 of the Interim Enforcement Policy) Civil Penalty - $30,000. The civil penalty of $40,000 for Severity Level III violation has been distributed between this item of noncomplaince and the following one, both of which together comprise an event.

B. NRC's letter to All Operating Nuclear Power Plants, dated October 30, 1979, titled "Discussion of Lessons Learned Short Term Requirements," provided additional clarification of these requirements, and stated "...it is not acceptable to assigns a person, who is normally the immediate supervisor of the shift supervisor to STA (Shift Technical Advisory duties...".

Contrary to the above, the Chief Operations Engineer, the immediate supervisor of the Senior Watch Supervisor, the licensee's equivalent title to a shift supervisor, was assigned to perform STA duties on the 7:00 AM to 3:00 PM, shift of October 17, 1980.

This is a Severity Level III violation. (Supplement I.C.2 of the Interim Enforcement Policy) Civil Penalty - $10,000.

IV. Technical Specification 6.8.1 requires that: "Written procedures shall be established, implemented and maintained..." Procedure E-12, "Nuclear Instrument Malfunction", Rev. 3 dated 7/5/78, step C-4.1.3 requires as "Immediate Operator Action", if one channel fails, that C-5.5 of Procedure E-12 subsequently requires that all the nuclear bistables associated with the defective channel be tripped by removing the control power fuses.

Contrary to the above: On October 17, 1980, the licensee removed the control power fuses associated with the defective channel N42, with reactor power level at about 90%. This resulted in an automatic runback to less than 75% reactor power.

This is a Severity Level V violation (Supplement I.E of the Interim Enforcement Policy).

Pursuant to the provisions of 10 CFR 2.201, Consolidated Edison Company of New York, Inc. is hereby required to submit to this office within twenty-five days of the date of this notice, a written statement or explanation in reply, including: (1) admission or denial of the alleged violations: (2) the reasons for the violations if admitted: (3) the corrective steps which have been taken and the results achieved; (4) corrective steps which will be taken to avoid further violations; and (5) the date when full compliance will be achieved. Under the authority of Section 182 of the Atomic Energy Act of 1954, as amended, this response shall be submitted under oath or affirmation.

Consolidated Edison Company may, within twenty-five days of the date of this Notice pay the civil penalty in the cumulative amount of Two Hundred Ten Thousand Dollars ($210,000) or may protest the imposition of the civil penalty in whole or in part by a written answer. Should Consolidated Edison fail to answer within the time specified, this Office will issue an order imposing the civil penalty in the amount proposed above. Should Consolidated Edison Company elect to file an answer in accordance with 10 CFR 2.205 protesting the civil penalty, such answer may (a) deny the item of noncompliance listed in the Notice of Violation in whole or in part; (b) demonstrate extenuating circumstances; (c) show error in the Notice of Violation; or (d) show other reasons why the penalty should not be imposed. In addition to protesting the civil penalty in whole or in part, such answer may request remission or mitigation of the penalty. Any written answer in accordance with 10 CFR 2.205 should be set forth separately from the statement or explanation in reply pursuant to 10 CFR 2.201, but may incorporate by specific reference (e.g., giving page and paragraph numbers) to avoid repetition.

Consolidated Edison Company's attention is directed to the other provisions of 10 CFR 2.205 regarding, in particular, failure to answer and ensuing orders; answer, consideration by this office, and ensuing orders; requests for hearings, hearings and ensuing orders; compromise; and collection.

Upon failure to pay any civil penalty due which has been subsequently determined in accordance with the applicable provisions of 10 CFR 2.205, the matter may be referred to the Attorney General and the penalty, unless compromised, remitted, or mitigated, may be collected by civil action pursuant to Section 234c of the Atomic Energy Act of 1954, as amended (42 USC 2282).

Victor Stello, JR.
Director
Office of Inspection and Enforcement

Dated at Bethesda, Maryland
this 11thday of December, 1980

APPENDIX B

DEC 1 1 1980

NOTICE OF DEVIATION

Consolidated Edison Company
of New York, Inc.
Indian Point Unit 2

Docket No. 50-247
License No. DPR-26

Based on the results of an NRC investigation conducted during the period October 22, 1980 to November 21, 1980, it appears that one of your activities was not conducted in accordance with standard industry practice or manufacturer's recommendations as indicated below:

Contrary to standard industry practice and the manufacturer's Technical Manual, "Goulds Installation, Operation, and Maintenance Instructions for Vertical Sump Pumps, Models 3171. 3172. 3173. 3174" the containment sump pump float rods were not attached or guided at the bottom from October 17, 1980 through October 20, 1980. This contributed to sump pump inoperability during the containment flooding incident. Also, contrary to guidance on page 9 of the manufacturer's Technical Manual, the pumps were not prevented from running against a shutoff head on September 14, 1980 and September 15, 1980 and at various times from October 17, 1980 to October 19, 1980 when the pump discharge valves were shut and power to the pumps was not secured.

In reply, please comment on this item, including a description of all actions that have been or will be taken to correct the item and prevent recurrence and the date when these actions have been or will be completed.

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PDR
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Consolidated Edison Company of New York, Inc.
4 Irving Place, New York, N.Y. 10003
Telephone (212) 460-2533

January 5, 1981

Re: Indian Point Unit 2
Docket No. 50-247

Mr. Victor Stello, Jr., Director
Office of Inspection and Enforcement
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Subject: Consolidated Edison's Response to Notice of Violation and Proposed Imposition of Civil Penalty dated December 11, 1980

Dear Mr. Stello:

This is in response to your letter of December 11, 1980, enclosing a Notice of Violation and Proposed Imposition of Civil Penalty resulting from your office's investigation of the recent accumulation of service water inside containment at Indian Point Unit 2. Your letter also proposed civil penalties characterized as based upon the October 7, 1980 Interim Enforcement Policy and remarked generally upon the management control system at Indian Point Unit 2. Pursuant to Consolidated Edison Corporate Instruction 250-1, your letter has been referred to me for reply.

It is apparent that on a number of matters we have drawn differing conclusions based upon information gathered during our independent investigations of the October event. Consolidated Edison has conducted its own extensive inquiry into the incident, and our comprehensive report on the event is in the final stages of preparation. While much has been and will continue to be done by us to prevent recurrence of an incident of this sort, we do not agree with the Office of Inspection and Enforcement's suggestion that the management control system at Indian Point Unit 2 was not functioning in an appropriate manner. The confluence of equipment failures necessary to permit the occurrence of this incident could not reasonably have been anticipated from events prior to October 17, 1980, and there were, in our judgment, no management system failures -- much less violations.

A report on Consolidated Edison's management control system at Indian Point Unit 2 was issued by your Office of Inspection and Enforcement on September 2, 1980, following an in-depth audit of our central and plant operations in July and August.

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Its conclusions on our attitude towards safety at Indian Point note that:

> "It was the general view that management interpreted the technical specifications literally or conservatively (with respect to safety) and that plant operators had no reservations about shutting the plant down if, in their opinion, technical specification limits or other safety considerations required it. Based on the above interviews, indications were that plant and corporate management's first priority was safe operation and that the operating staff was aware of this priority."

Our differing views on these and several other matters relating to the event were arrived at only after a careful consideration of the information and conclusions set forth in your December 11 letter and its enclosed Notice. Our consideration has been substantially aided by the many studies and analyses which we and others have performed since October. Our responses are set forth in two enclosures to this letter: Consolidated Edison's Statement in Reply to Notice of Violation, and Consolidated Edison's Answer to Notice of Proposed Imposition of Civil Penalty. We also enclose a third document which addresses the four alleged unreviewed safety questions referred to in your December 11 letter.

Our major differences of view can be summarized as follows: (1) our use of epoxy materials in repairing service water piping was prudent and effective, and not a contributor to the event; (2) the maintenance and failure detection program for service water system leakage, in conjunction with the design of related plant systems, was appropriate for the infrequent pinhole leaks which had been experienced at the unit during its prior operating history; (3) our conclusion that there were no problems with the safe operation of the plant at any time during the event is correct and has in fact been borne out by our analyses, even though your findings of violation, and in particular your proposed severity levels, implicitly assume that there was a high degree of potential impact on the public; and (4) while we have previously acknowledged that the events discovered on October 17 should have been promptly reported to the NRC, the NRC reporting requirements as set forth at the time of the event were unclear, and in light of your present claims, provided an inadequate level of guidance for operator conduct.

The Notice of Violation does not acknowledge that certain operational conditions or circumstances now perceived by your Office as problems were simply unrecognized prior to the event, and thus not addressed either by NRC regulations or by key unit operational documents. Many of the regulatory requirements now cited as the basis for violations are in our judgment ill-suited to support the Office of Inspection and Enforcement's violation claims. As such, we believe that your Office has neglected a key provision of the Interim Enforcement Policy:

> "Corrective enforcement actions may be taken in the absence of any violation of NRC requirements; for example, when a safety problem not previously covered by a requirement is discovered. NRC imposes civil penalties, however, only on the basis of a violation of an existing requirement. "(45 FR at 66755).

Our careful review of the Notice of Violation leads us to the conclusion that there were other instances where the new (October 7, 1980) Interim Enforcement Policy was not followed. In particular, in both concluding that violations existed, and in assessing severity levels, the Notice of Violation accords vague and, in this instance, unsupportable interpretations to such broad terms as "controlled or expected condition," "abnormal degradation in containment," "modification," and "actual or high potential impact on the public," none of which could reasonably have been so interpreted by nuclear power plant operators prior to the occurrence.

The Notice also misapplies severity levels by assuming actual safety implications existed as a consequence of the event when in fact our investigations revealed none. Lastly, the Notice unfairly and improperly applies footnote 17 of the Interim Enforcement Policy (45 FR at 66757) to "bootstrap" lesser alleged violations into higher categories and to create multiple violations out of single events without a proper basis. Because of the importance to industry enforcement generally of the Office of Inspection and Enforcement's unprecedented (and in our view unwarranted) interpretation of the Policy in this instance, we have taken the liberty of sending a copy of this letter to the Commission Secretary and the Executive Director for Operations, in order that it may be considered in connection with the current round of solicitation of comment on the Interim Enforcement Policy.

Although we are unable to concur with many of the conclusions of the Office of Inspection and Enforcement that violations occurred, it is clear to us that a revised and heightened consideration of various potential implications of service water system leakage should be made by Consolidated Edison and the nuclear industry generally. To identify the nature of the desired changes, we have undertaken an extensive internal review of management operations in the area of component failure assessment. While many of the numerous changes intended to prevent recurrence have been previously provided to the NRC for review, and most recently in our letter of December 22, 1980, it may be useful to mention them again here. Programmatic changes are planned, such as revisions to the Quality Assurance Program and redefinition of certain of the functions of the

Station Nuclear Safety Committee. Implementation changes include revisions to notification, maintenance and surveilance procedures. These changes and further training of personnel to accomplish them will result in additional improvements in the management control system for Indian Point Unit 2.

In addition, we are reviewing our existing organizational structure for operation and operations support at Indian Point in light of recent guidance (September 23, 1980; Vargas to Zarakas) issued by the NRC, to determine if changes could beneficially be made. To date, one such change has been identified as warranted. In several instances, the management control concern centers on implementation of the 10 CFR 50 Appendix B quality assurance program. This program at Con Edison could be beneficially modified by a re-organization of the organizations responsible for implementation and oversight. We plan to have all the Indian Point QA/QC function be part of the Central Quality Assurance and Reliability Department which reports to offsite management independent of power generation.

These changes and our commitment to continuous improvement in the operation of Indian Point Unit 2 demonstrate our intent to implement whatever actions appear appropriate to prevent recurrence of the matters outlined in your letter. We want to assure you of our firm resolve to take all necessary steps to continue our eighteen-year record of safe operation of nuclear power plants at Indian Point. We look forward to working with the appropriate offices of the Commission in this effort.

Very truly yours,

John D. O'Toole
Assistant Vice President

Enclosures

cc: Mr. Samuel J. Chilk, Secretary to the Commission
Mr. William J. Dirks, Executive Director for Operations
Mr. Boyce H. Grier, Director Region I
Mr. Theodore Rebelowski, Resident Inspector

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
631 PARK AVENUE
KING OF PRUSSIA PENNSYLVANIA 19406

DEC 4 1980

Docket No. 50-247

Consolidated Edison Company of
New York, Inc.
ATTN: Mr. Eugene McGrath
Vice President
4 Irving Place
New York, New York 10003

Gentlemen:

Subject: Investigation 50-247/80-19

An investigation into the containment flooding at Indian Point Unit 2 on October 17, 1980 was conducted from October 22 through November 21, 1980. The results of this investigation are described in the enclosed report, as Enclosure 1 to this letter. The report is being provided to you for proprietary review as indicated below. The enforcement correspondence pertaining to this investigation will be provided separately by the Director, Office of Inspection and Enforcement, Washington, D. C.

Based on discussions between Mr. E. McGrath of your company and Mr. T. Martin of our office on November 21 and December 3, 1980, we understand that you have committed to provide to the NRC the reports identified in Enclosure 2 to this investigation report by December 22, 1980 and that you have committed to submit by February 15, 1981 or prior to restart if later, proposed revisions to your Technical Specifications for new or modified systems. If our understanding of these commitments is incorrect please notify this office within 24 hours.

On December 3, 1980, a meeting was held at the Region I Office, between you and members of your staff and me and members of my staff, to discuss additional factual information not previously made available to our investigators. The results of this meeting are described in Enclosure 2 to this letter.

In accordance with Section 2.790 of the NRC's "Rules of Practice," Part 2, Title 10, Code of Federal Regulations, a copy of this letter and the enclosed investigation report will be placed in the NRC's Public Document Room. You were provided an advance copy of this report on December 1, 1980, for early proprietary review. If this report contains any information that you (or your contractor) believe to be proprietary, it is necessary that you make a written application to reach this office by close of business December 4, 1980, to withhold such information from public disclosure. Any such application must be accompanied by an affidavit executed by the owner of the information, which identifies the document or part sought to be withheld, and which contains a statement of reasons which addresses

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with specificity the items which will be considered by the Commission as listed in subparagraph (b) (4) of Section 2.790. The information sought to be withheld shall be incorporated as far as possible into a separate part of the affidavit. If we do not hear from you in this regard within the specified period, the report will be placed in the Public Document Room.

Should you have any questions concerning this investigation, we will be pleased to discuss them with you.

Sincerely,

Boyce H. Grier

Boyce H. Grier
Director

Enclosures:
1. Office of Inspection and Enforcement Investigation Report Number 50-247/80-19 with two enclosures
2. Office of Inspection and Enforcement Meeting Report Number 50-247/80-19A

cc w/encls:
L. O. Brooks, Project Manager, IP Nuclear
W. Monti, Manager - Nuclear Power Generation Department
M. Shatkouski, Plant Manager
J. M. Makepeace, Director, Technical Engineering
W. D. Hamlin, Assistant to Resident Manager
J. D. Block, Esquire, Executive Vice President - Administration
Joyce P. Davis, Esquire
Brent L. Brandenburg, Assistant General Counsel

DCS 50247-801017

NOTICE DEC 4

U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

Region I

Report No. 50-247/80-19

Docket No. 50-247

License No. DPR-26 Priority -- Category C

Licensee: Consolidated Edison Company of New York, Inc.

4 Irving Place

New York, New York 10003

Facility Name: Indian Point Nuclear Generating Station, Unit 2

Investigation at: Buchanan, New York

Investigation conducted: October 22 - November 21, 1980

Investigators:

T. T. Martin, Chief, Reactor Projects Section No. 3, RO&NS Branch	11/28/80 date signed
T. T. Martin for T. A. Rebelowski, Senior Resident Inspector, Indian Point	11/28/80 date signed
for J. C. Higgins, Senior Resident Inspector, Shoreham	11/28/80 date signed
T. T. Martin T. J. Kenney, Resident Inspector, Indian Point	11/28/80 date signed
S. D. Reynolds, Reactor Inspector, Engineering Support Section 1, RC&ES Branch	11/28/80 date signed
for R. A. McBrearty, Reactor Inspector, Engineering Support Section 1, RC&ES Branch	11/28/80 date signed
G. Napuda, Reactor Inspector, Nuclear Support Section No. 2, RO&NS Branch	11/28/80 date signed
for R. E. Shepherd, Investigation Specialist	11/28/80 date signed
R. H. Smith, Investigation Specialist	11/28/80 date signed

Approved:

J. M. Allan, Deputy Director	11/28/80 date signed

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Region I Form 12
(Rev. April 77)

Investigation Summary:

Investigation on October 22 - November 21, 1980 (Report No. 50-247/80-19)

Areas Investigated: Investigation of the circumstances leading to and the results of the Vapor Containment Floor and Reactor Vessel Pit flooding event on October 17, 1980. Areas examined included: Sequence of Events; Licensee Management Activities; Shift Technical Advisor; Reporting; Reactor Trip and Instrumentation Performance; Containment Sump Pumps and Level Instrumentation; Reactor Vessel Pit Sump Pumps; Leak Detection Instrumentation and Procedures; Fan Cooler Units; Reactor Vessel Pit Flooding; Flooding History; Reactor Vessel Integrity Following Immersion; Containment Paint and Insulation; Mirror Insulation; Steam Generator Blowdown Line Leaks and Supports; Corrosion Effects of River Water; Chloride Containment Survey; Non-Destructive Examinations; Quality Assurance and Quality Control Programs; and, System Descriptions. The investigation involved 1300 inspector hours onsite by one Section Chief, six inspectors, and two investigators.

Results: Ten items of noncompliance were identified: (Failure of the Station Nuclear Safety Committee to review potential safety hazards prior to Reactor Startup, Paragraph 4.b; Assignment of an unqualified individual to Shift Technical Advisor duties, Paragraph 5.c; Failure to follow Emergency Procedure for Inoperable Power Range Nuclear Instrument, Paragraph 7.f; Failure to report the Vapor Containment Flooding Event, Paragraph 5.d; Failure to establish adequate procedures, Paragraphs 8.c.(4), 10.b.(4), 10.c.(4), and 22.d; Failure to adequately evaluate the use of Epoxy Material as a Fan Cooler Unit repair material, Paragraph 22.d; Failure to determine, evaluate, and record the causes of leaks, Paragraph 22.d; Failure to promptly respond to QC Inspection Reports, Paragraph 22.c; and, Failure to control and identify material, Paragraph 11.g). One deviation was identified: (Contrary to industry practice, Vapor Containment Sump Pumps were operated without float controller lower guides and with shutoff heads, Paragraph 8.c.(4)).

DETAILS

1. Persons Contacted

The management and supervisory personnel listed below were contacted:

E. Baisel, Instrumentation and Control Supervisor
A. Brescia, Instrumentation and Control Supervisor
J. Cullan, General Supervisor - Health Physics
J. Curry, Chief Operations Engineer
W. Ferreira, Quality Assurance Engineer
R. Flynn, Instrumentation and Control Technician
J. Halpin, Maintenance Engineer
A. Hauspurg, President
J. Higgins, General Chemistry Supervisor
W. Lettmoden, Senior Watch Supervisor
C. Limoges, Reactor Engineer
*J. Makepeace, Technical Engineering Director
*E. McGrath, Vice President of Power Generation
T. McKenna, Maintenance Foreman
*W. Monti, Manager-Nuclear Power Generation
A. Nespoli, Refueling Engineer
R. Orzo, Senior Watch Supervisor
J. O'Toole, Assistant Vice President, Engineering
E. Phillips, Manager, Field Office Quality Assurance
C. Powell, Senior Watch Supervisor
D. Sarc, Acting Maintenance Engineer
T. Schmeiser, Support Facility Supervisor
*M. Shatkouski, Plant Manager
R. Vogle, Health Physics Supervisor
T. Walsh, Instrumentation and Control Engineer
W. Wedler, Qaulity Control Engineer
S. Wisla, Chemistry and Radiation Safety Director
P. Zarakas, Vice President of Engineering

The investigators also interviewed or contacted additional personnel from the operations, health physics, chemistry, test, maintenance, engineering, quality assurance, and adminstrative staffs.

*denotes those individuals present at the exit interview conducted by the NRC Investigation Team on November 18, 1980.

2. Event Summary

Shortly after midnight on Friday, October 17, 1980, operators detected and later verified that one of four Power Range Nuclear Instrument Channels was failing. Following the declaration of the Channel to be inoperable, operator failed to first reduce the Plant power to less than seventy percent before deenergizing the Channel, resulting in an automatic Turbine runback to seventy percent.

During attempts to over-ride the automatic Turbine runback controls, operator turned one of the Turbine load limiters in the wrong direction, causing a further reduction in Turbine power and ultimately a Reactor Trip.

Confident the cause of the runback and trip were known, and being allowed to operate with one Power Range Nuclear Instrument Channel inoperable, the Plant was restarted. With the inoperable Nuclear Instrument Channel in a tripped condition, technicians trouble-shooting the Instrument Channel problem injected a test signal into a second Nuclear Instrument Channel causing it and the Reactor to trip.

Again, confident the trip was understood, the Plant was restarted. Shortly following the return to criticality, licensee management directed the Plant be shutdown to repair the trouble with the inoperable Channel, now known to be within the associated cables or detectors, located within the Vapor Containment.

The first Vapor Containment entry team found several inches of water on the Vapor Containment Floor and river water leaks on a Fan Cooler Unit. The second entry team found hot, humid vapor exiting the Nuclear Instrument Channel detector well, additional Fan Cooler Unit leaks, two Vapor Containment Sump Pumps inoperable and ankle deep water (later proven to be river water) on the Vapor Containment Floor.

A supervisor restarted one of the Vapor Containment Sump Pumps by righting both float operators and restarted the other Pump after replacing its blown fuses. Later, the same supervisor checked for and found water in the Reactor Vessel Pit, several feet below the access grate. Neither he or his supervisors recognized that the water level he reported corresponded to a nine foot level on the outside of the Reactor Vessel.

During the weekend, water was pumped from the Reactor Vessel Pit and Vapor Containment, a leak identified on one Steam Generator Blowdown Line was repaired, and the multiple leaks on each Fan Cooler Unit were repaired.

Early in the morning on Monday, October 20, 1080, with the leaks repaired and the Vapor Containment Floor and Reactor Vessel Pit dry, the Plant was restarted. The Plant was subsequently shutdown when licensee management, returning to work, learned of the flooding of the Reactor Vessel Pit and were concerned with the potential of Chloride Stress Corrosion of the Stainless Steel Incore Instrument Conduits.

Subsequent discussions with the NRC included identification of the concern for the potential that the Reactor Vessel was wetted and the commitment to

NRC that the plant would not be restarted, without first giving NRC four hours warning.

By Monday evening, preliminary licensee calculations of the amount of water pumped from the Vapor Containment and the amount of water necessary to flood to the evelvation of the bottom of the Reactor Vessel, indicated that the Reactor Vessel had not been wetted. The previous observations of the supervisor initially discovering the water in the Reactor Vessel Pit were not compared to Vapor Containment construction elevation drawings at this time. Subsequent water inventory calculations on Monday and Tuesday placed the conclusion, that the Reactor Vessel had not been wetted, in doubt.

On Tuesday afternoon, October 21, 1980, NRC had documented the corrective actions expected of the licensee, had obtained the licensees commitment to complete those actions, and had finalized those actions expected in an Immediate Action Letter, that would be issued the following morning.

The plant was maintained in a hot shutdown condition until Tuesday evening, when the licensee recognized the need to remove the Reactor Vessel Insulation to conduct tests to determine if the Reactor Vessel had been wetted. On Wednesday morning the initial Chloride Swipe Surveys of the Reactor Vessel supported the licensee's belief but subsequent Swipes with the Plant now in Cold Shutdown again raised concerns that the Reactor Vessel had been wetted.

On Wednesday evening, the NRC Investigation Team arrived on site and began to gather information.

Operators returning from two days off on Thursday, learning of management's investigation, informed their supervisors of their observations of water level in the Reactor Vessel Pit. The reports of these observations, coupled with Friday morning's Reactor Vessel Swipe Survey Analysis results demonstrating the residue was from river water, convinced the licensee that the Reactor Vessel had been at operating temperature while submerged in relatively cool river water to a depth of about nine feet.

During a meeting on Friday, October 24, 1980, the NRC Investigation Team was informed of the licensee's conclusions.

3. Conduct of Investigation

The NRC Investigation of the Vapor Containment Flooding event was initiated on October 22, 1980, and was concluded on November 21, 1980; involved approximately 1300 man-hours; and, was conducted by a team consisting of:

1 - Section Chief
2 - Senior Resident Inspectors
1 - Resident Inspector
1 - Reactor Inspector (Quality Assurance)
1 - Reactor Inspector (Non-Destructive Examination)
1 - Reactor Inspector (Corrosion and Metallurgy)
2 - Investigators

Information was gathered through the conduct of interviews, the taking of sworn statements, the inspection of equipment and tours of affected spaces, the review of procedures, records, logs, and computer printout, the witnessing of tests, independent computation of volumes and flooding elevations, the construction of charts and information flow diagrams, and the independen non-destructive examination of the Reactor Vessel and Incore Instrument Conduits.

The principle products of this investigation are the transcript of the NRC-licensee Technical Meeting in White Plains, New York on November 5, 1980; and this investigation report, including a detailed Sequence of Events attached as Enclosure 1 to the report.

Based on the findings of the NRC Investigation Team and that of the licensee it was determined that additional information relative to the event and the corrective action required to prevent reoccurrence had to be developed and documented. Enclosure 2 documents those reports the licensee has committed to develop and submit to NRC by December 22, 1980. The licensee is further committed to propose new or additional Technical Specifications for the systems contributing to the flooding event, or modified as a result of the event, by January 15, 1980.

4. Licensee Management Activities

a. Event Narrative

(1) Friday - 10/17/80

Upon discovery of the problem with Nuclear Instrument Channel N42, shortly after midnight, operators notified the first shift Senior Watch Supervisor (S.W.S.) (first line supervision) of the condition, who then called the Chief Operations Engineer (C.O.E.) at home and informed him of the problem. It was decided that the S.W.S. would call the Reactor Engineer and request he come to the plant to conduct a flux map. The C.O.E. called the Plant Manager (P.M.) at home and informed him of the developing problem.

Following the determination by the Reactor Engineer and S.W.S. that Channel N42 was failing and should be declared inoperable, the S.W.S. again called the C.O.E., requesting per licensee procedure that the C.O.E. get permission from the P.M. to operate above 70 percent power with only three Power Range Nuclear Instrument Channels operable. The C.O.E. called and received the required permission, but whether this permission was passed to the S.W.S., prior to pulling the fuses on Channel N42 while at 90 percent power and the resulting Turbine runback, is unclear.

The S.W.S. called the licensee's Operation Control Center (O.C.C.) and informed the watch stander of the runback. Whether the S.W.S. then called the C.O.E., or vice versa, is unclear, but permission to operate above 70 percent was given. The S.W.S. decided to deenergize the Turbine Load Limiters, used by the controls to implement the Turbine runback, and move them out of the way so that power could be raised.

Following the combination operator error-communication failure, that resulted in one load limiter being moved in the wrong direction causing a drop in Turbine Load and Reactor Scram, the S.W.S. again called the O.C.C. and the C.O.E. at home to inform them of the latest events. Based on their confidence that the cause of the trip was known and that no safety problem existed, the S.W.S. recommended and the C.O.E. concurred with plans to restart the plant. The C.O.E. then called the P.M. to inform him of the latest events and to confirm that his decision to restart the plant was appropriate.

The S.W.S. then notified the NRC Duty Officer of the Turbine Runback and Reactor Trip.

The Vice President (V.P.) - Power Generation called the O.C.C. shortly after 6:00 AM, to learn the status of the Power Generation system, and learned of the first Reactor trip and plans for restart at Indian Point Unit 2.

During the conduct of a morning management meeting, which included discussion of the events of the morning, the Reactor was tripped a second time through a technical error. Instrumentation and Control (I&C) Supervisors trouble-shooting Channel N42 problems had decided to run response checks on Channel N41 for the purpose of comparison. One Supervisor was unaware that changing the Channel top to bottom detector difference current could depress the Over-Power Delta "T" trip setpoint to the point where a trip could occur with the Reactor at only 3 percent power. The other Supervisor was unaware that the flux difference entered the setpoint calculation. With the trips still in on Channel N42, the trip of Channel N41 satisfied the Reactor Protection System logic, yielding the Reactor Trip.

The second shift S.W.S. notified the O.C.C. and the C.O.E., now on site, of the trip. The C.O.E. and P.M. concurred in the S.W.S.'s recommendation to restart the Plant, based on their confidence that no safety issue was involved.

The S.W.S. subsequently notified the NRC Duty Officer of the Reactor Trip.

As the Plant was being restarted, the P.M. was informed that the problem with Channel N42 had now been isolated to the detector and/or cables within the Vapor Containment, that spare parts were available, that repairs would only take several hours, that operation with one Channel inoperable required daily flux maps with the attendant wear of the Incore Instrument System, and the increased probability of a spurious Reactor trip operating with the now required one out of three trip logic. Based on the projected load demand for the weekend and the fact union personnel would assist in the repairs if the Reactor were shutdown, the P.M. directed the C.O.E. to shutdown. The C.O.E. entered the Control Room as the Reactor went critical and directed the S.W.S. to place the Plant in hot shutdown and prepare for Vapor Containment entry. The S.W.S. caused the Reactor to be shutdown shortly after 10:00 AM.

Preparations for Vapor Containment entry began immediately. The seven man entry team included the I&C Engineer and the I&C Supervisors. Upon the discovery that the Vapor Containment lights were out on the upper floors, that Fan Cooler Unit (F.C.U.) No. 22 was leaking and that the Vapor Containment Floor was covered with several inches of water, the entry team left the Containment and the I&C Engineer notified the Control Room and the P.M. of the conditions found.

After a change of anti-contamination clothes to accommodate the presence of water on the floor, the entry team again entered the Vapor Containment, intent on replacement of the Channel N42 Detector. The team found the water on the floor deeper inside the Vapor Containment Missile Shield, water flowing from all four of the F.C.U. condensate weirs which they passed, and a hot-humid vapor exiting the top of the Nuclear Instrument Channel Detector Well. During the period the entry team was inside the Vapor Containment, the S.W.S. directed the Support Facility Supervisor (S.F.S.) to enter the Vapor Containment and investigate problems identified by the entry team.

The entry team exited the Containment about 2:00 PM, notified the Control Room and P.M. of their findings and inability to replace the detector, and met in the P.M.'s office to discuss the situation

(It appears that neither the C.O.E. or licensee management above the P.M. were made aware of the observation of steam vapor rising from the Detector Well, until several days later). During the meeting, the Technical Engineering Director (T.E.D.) asked what level of water had been observed. When informed that the level was 2 to 4 inches, the T.E.D. reportedly indicated that since the water had not approached the height of the 6 inch curb around the accesses to the Reactor Vessel Pit, that flooding of the Pit could not have occurred. In response to his question, the P.M. was assured that operations (the S.F.S.) was investigating the problem. It was agreed that the T.E.D. would inform the NRC Resident Inspector of the identified problems.

The S.F.S., now in Vapor Containment, had found both Vapor Containment Sump Pumps inoperable, had started one by righting its float and started the other by replacing its fuses, had identified the major leak on F.C.U. #22 to be from the Service Water Return Line, and thought he had verified that at least one Reactor Vessel Pit Sump Pump was running (the indicating light he examined and found lit means that moisture had entered the upper seal on the motor cables).

The S.F.S. exited Containment to get tools to remove Service Water Return Line Insulation and inform the Control Room of his findings. He then returned to the Vapor Containment, removed the Service Water Return Line Insulation and pinpointed the leak, identified a number of other F.C.U. leaks, and verified the Vapor Containment Sump Pumps were working.

During the second shift, the C.O.E. simultaneously held the position of S.T.A. and C.O.E. This dual roll had him responsible for making decisions and directing operations important to commercial operations, at the same time he was responsible for the independent and detached observation of operations, as an individual dedicated to plant safety. (That one of the S.T.A.'s in training could have been called to the Control Room during this period is not questioned. The fact is that one was not called and the flooding event was not recognized for what it was by the individual assigned that responsibility). (This item is addressed further in paragraph 5).

Around 3:00 PM, the T.E.D. attempted to reach the NRC Resident Inspector, found him not in the office, and left a message on his telephone answering machine to please return the call. He did not mention the subject of his call, but reportedly intended to inform the Resident of the failure of a Main Steam Isolation Valve to fully close earlier that day (the T.E.D. had previously determined that to be reportable under the licensee's Technical

Specifications for 30 day reports) and that some Service water from F.C.U. leaks had been found on the Vapor Containment Floor.

Later that afternoon, during a telephone conversation, the V.P.-Power Generation was informed of the events of the day by the P.M. Although the fact that F.C.U. leaks had been identified was mentioned, it is unclear that the presence of water on the floor was discussed at this time. The fact that the Plant was shutdown and that F.C.U. leaks were being repaired was subsequently discussed by the V.P.-Power Generation with the President later that evening.

Shortly after 6:00 PM, the S.F.S. returned to the Vapor Containment and at the request of the C.O.E., checked to see if there was any water in the Reactor Vessel Pit. The S.F.S. found the Reactor Vessel Pit to be flooded to within 4 feet of the elevation 46 feet floor grating. The S.F.S. subsequently left the Containment and informed the C.O.E. and the third shift S.W.S. of his findings. (No one connected this observation with a potential submerged condition of the Reactor Vessel, each believing the Reactor Vessel Lower Head was at a significantly higher elevation. Therefore, no one checked elevation drawings to resolve the concern, which should have existed). Before leaving the site for home, the C.O.E. called the P.M. at home to inform him of the condition of the Reactor Vessel Pit. It is unclear whether the observed flooding level was communicated. (The P.M. apparently did not pass this information on to the V.P.-Power Generation). The C.O.E. directed the S.W.S. to pump the water from the Vapor Containment Floor and the Reactor Vessel Pit. The C.O.E. left night orders directing the S.W.S. to continue preparations for a Plant startup.

The S.W.S. subsequently directed efforts to obtain and install submersible pumps in the Reactor Vessel Pit and repair leaking F.C.U.s.

(2) Saturday - 10/18/80

The first shift S.W.S. succeeded in having a submersible pump installed in the Reactor Vessel Pit and had some success in reducing the water level. Efforts continued to prepare for an eventual Reactor startup, now predicted for 9:00 AM, that morning.

The second shift S.W.S. informed the O.C.C. around noon that the Reactor would be critical at about 2:00 PM, that day. Subsequently he toured the Vapor Containment, found a leak on a Steam Generator Blowdown Line, a leak on another F.C.U. and a need to lower the

Reactor Vessel Pit Portable Submersible Pump to ensure it was able to pump out the rest of the water. Upon exiting the Containment, he informed the C.O.E. of his findings.

The C.O.E. called the P.M. at home, informing him of developments. The P.M. subsequently informed the V.P.-Power Generation of the discovery of the leak on the Steam Generator Blowdown Line. Apparently, the P.M. again failed to mention the water in the Reactor Vessel Pit.

Subsequently, the Outage Coordinator called the O.C.C. at about 4:00 PM, informing the watch stander that the Unit would be delayed in its return to power and requesting assistance in locating welders qualified to repair the Steam Generator Blowdown Line leak.

(3) Sunday - 10/19/80

The first shift S.W.S. succeeded in lowering the Reactor Vessel Pit Portable Submersible Pump about 5 feet. Little if any water had been removed since noon, the day before. It subsequently was determined that the pump had siezed and required replacement.

The second shift S.W.S. toured the Vapor Containment, found little if any water had been removed within the last 24 hours, and found one Vapor Containment Float Controller cocked. Subsequent discussion between the S.W.S. and the C.O.E. identified a potential for a siphon path from the Vapor Containment Sump to the Reactor Vessel Pit, using the Reactor Vessel Pit Sump Pumps' common discharge line. It was agreed to drill a hole in the line above the Vapor Containment Sump to provide Reactor Vessel Pit Sump Pump flow indication and an anti-siphor vacuum breaker.

The V.P.-Power Generation called the O.C.C. at about noon to determine the status of the Power Generation System. He subsequently called the S.W.S. and was informed of the problem in pumping the water from the Reactor Vessel Pit. The V.P.-Power Generation was not aware that F.C.U. water had flooded the Vapor Containment, thought the water in the Pit was fresh water from the Steam Generator Blowdown Line leak, and offered assistance in locating pumps to assist in the effort. (It is not clear if the current Pit water level was discussed at this time; but even if it had been, the level was now below the Reactor Vessel and the V.P.-Power Generation believed the water to be fresh).

During the evening, the C.O.E. and P.M. decided to restart the Plant once the F.C.U. leaks were repaired and the water had been pumped below the Incore Instrument Conduits. (Although both men were aware of the Chloride content of the river water which had flooded the Reactor Vessel Pit, and the fact that the Conduits were made of Stainless Steel, neither was concerned with the potential for Chloride Stress Corrosion, since both realized an elevated temperature was required and that only the last couple of feet of the conduit, immediately under the Reactor Vessel, reached these temperatures. Again, the lack of perspective as to the elevation of the bottom of the Reactor Vessel Lower Head, had failed to sensitize them to a real concern).

The third shift S.W.S. had operators install a second Reactor Vessel Pit Portable Submersible Pump. The first Pump was now working, but improper connections prevented the second Pump from being effective.

(4) Monday - 10/20/80

The first shift S.W.S. learned he was to restart the Plant once the F.C.U. leaks were repaired and the Reactor Vessel Pit water level was below the Incore Instrument Conduits. At 5:30 AM, he informed the O.C.C. that the shift was closing the Vapor Containment in preparation for return to power. Prior to watch relief, the S.W.S. informed the O.C.C. the Reactor was critical.

The T.E.D., returning from a weekend off, reviewed logs about 7:30 AM and learned of the flooded condition of the Reactor Vessel Pit. The logs did not indicate water level, but clearly implied the Incore Instrument Conduits had been submerged.

The Manager - Nuclear Power Generation (N.P.G.), returning to site from a weekend plus two day vacation period, independently learned through log review and discussing with personnel of the flooding of the Reactor Vessel Pit. His concern for the potential of Chloride Stress Corrosion of the Incore Instrument Conduits was reinforced by the same concern of the T.E.D. A meeting was held between the Manager - N.P.G., the P.M. and the C.O.E. to discuss Plant status at about 8:30 AM. Based on these discussions the Manager - N.P.G. decided to place the Plant in hot shutdown and verify that no damage had occurred. The Manager-N.P.G. called the V.P.-Power Generation, informed him of his concerns and decision, and received the V.P.'s concurrence in his decision to shutdown. The Manager - N.P.G. directed the T.E.D. to notify the NRC Resident Inspector. The C.O.E. went to the Control Room and directed the Plant be placed in hot shutdown.

Subsequently, the T.E.D. attempted to return the 8:00 AM return call of the NRC Resident Inspector, responding to the Friday message on the answering machine, and to fulfill the direction given him by the Manager - N.P.G. Telephone contact was finally made at about 11.30 AM, when the T.E.D. informed the Resident that some water had been found on the Vapor Containment Floor over the weekend and that the Plant had been critical earlier that morning, but was now in hot shutdown.

At about noon, the Assistant V.P.-Engineering and the V.P.-Engineering were informed of the Manager - N.P.G.'s concerns. Site management had already initiated swipe surveys of Incore Instrument Conduits (to determine flooding and residue contamination levels), calculations to quantify the water pumped from the Vapor Containment and studies to develop water volume versus flooding elevation data. Corporate Engineering duplicated some of the latter site efforts and initiated calculations to bound the effects of the flooding event.

During the late afternoon, the Manager - N.P.G. responding to an NRC telephone inquiry, explained the licensee's plans and indicated the licensee's belief that the Reactor Vessel had not been wetted.

Later that afternoon at about 5:20 PM, the P.M. and T.E.D., responding to another NRC telephone inquiry committed to notify NRC four hours prior to any restart. The licensee maintained and believed his waste water volume calculations supported his contention the Reactor Vessel had not been wetted. (It should be noted that these calculations were being performed by the C.O.E. and at least one other individual. Why the C.O.E. did not remember the S.F.S.'s initial water level observation report and recognize that this water level meant the Reactor Vessel had been wetted, has not been determined. The S.F.S. was not involved in these calculations, had no reason to believe the Reactor Vessel had been wetted, knew others more senior then he were aware of his observation if he even thought about it, and just had no reason to independently do the research to determine if his knowledge was critical to the resolution of the licensee's problem).

(5) Tuesday - 10/21/80

The licensee continued inspections, calculations and studies initiated earlier to resolve concerns raised relative to the potential for wetting of the Reactor Vessel and the submergence of the Incore Instrument Conduits in river water. Initial results were encouraging, but not conclusive.

The licensee continued to perform precritical checks, but by early afternoon the Manager - N.P.G. decided to proceed to cold shutdown to enable more thorough examination, and if necessary, cleaning of the Reactor Vessel.

At about this time, the Manager - N.P.G., responding to the solicitation of NRC, committed to meet the requirements of Immediat Action Letter IAL 80-41.

(6) Wednesday - 10/22/80

The licensee's earlier efforts continued.

(7) Thursday - 10/23/80

The licensee's earlier efforts continued.

At about 7:30 AM, licensee management met with the NRC Investigation Team to explain the scope and status of their efforts and learn of the intent of the Team, its needs and required support.

The second shift S.W.S., returning from a period of 72 hours off, found the Plant in cold shutdown. When he had left on Monday, it had just returned to power. Reports of Reactor Vessel Pit water level, observed by three of his operators, who installed the first Portable Submersible Pump on Saturday morning, were rediscovered early that afternoon. The S.W.S. communicated this information to the V.P.-Generation, who then in turn, notified the NRC Investigation Team of the reported information and the names of the individuals.

(8) Friday - 10/24/80

The licensee's earlier efforts continued. Early in the morning, it was positively determined that the residue on the Reactor Vessel was from boiled river water. The V.P.-Power Generation called the NRC Investigation Team of this finding.

At approximately noon, the licensee met with the NRC Investigation Team and reported their conclusion that the Reactor Vessel had been submerged in river water to a depth of about 9 feet, while in hot shutdown.

b. Findings

The Plant Manager is the Chairman and the Chief Operations Engineer is a permanent Member of the Station Nuclear Safety Committee. Technical Specifications 6.5.1.6 requires in part, that "the Station Nuclear Safety Committee shall be responsible for: ...Review of facility operations to detect potential safety hazards." The Station Nuclear Safety Committee did not review, prior to a reactor startup on October 20, 1980, the potential safety hazards associated with the flooding event of October 17, 1980, during which the hot reactor vessel and various stainless steel components were wetted with cold, high chloride river water. This is an item of noncompliance (50-247/80-19-01).

5. Shift Technical Advisor

a. References

-- NUREG-0578, TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations

-- Letter dated 9/13/79 from D. G. Eisenhut, Acting Director, Division of Operating Reactors to All Operating Nuclear Power Plants, titled, "Followup Actions Resulting From the NRC Staff Reviews Regarding the Three Mile Island Unit 2 Accident"

-- Letter dated 10/30/79 from H. R. Denton, Director, Office of Nuclear Reactor Regulation to All Operating Nuclear Power Plants, titled, "Discussion of Lessons Learned Short-Term Requirements"

-- Confirmatory Order dated 2/11/80 from H. R. Denton, Director, Office of Nuclear Reactor Regulation to Consolidated Edison Company of New York, Inc.

-- Letter dated 9/5/80 from D.G. Eisenhut, Director, Division of Licensing to All Licensees of Operating Plants and Applicants for Operating Licenses and Holders of Construction Permits, titled, "Preliminary Clarification of TMI Action Plan Requirements"

-- OAD-9, Revision 3, Indian Point Station, Operations Subsection Administrative Directive, titled, "Operations Subsection Organization"

b. Requirements

(1) NUREG-0578 documented the Lessons Learned Task Force recommendation to establish the position of the Shift Technical Advisor (S.T.A.). The key elements of this recommendation are listed below.

(a) Provide on shift a technical advisor to the shift supervisor with a technical degree, or its equivalent, and with specific training in the plant's response to off normal conditions and accident assessment.

(b) Assign the S.T.A. normal duties pertaining to the engineering aspects of assuring safe operation, including the review and evaluation of operating experiences.

In discussing the purpose of the recommendation, NUREG-0578 provided the following additional clarifications.

(c) That additional technical and analytical capability, dedicated to concern for the safety of the plant, needed to be provided in the control room to support the diagnosis of off-normal events and to advise the shift supervisor on actions to terminate or mitigate the consequences of such events.

(d) When assigned as S.T.A., the individual is to have no duties or responsibilities for manipulation of controls or command of operations.

(e) Consideration should be given to the need to license the S.T.A.'s.

(2) By letter to all licensees dated 9/13/79, the requirement for the establishment of the S.T.A. position was issued. Licensees were required to have the S.T.A. on duty by 1/1/80, and to have S.T.A. training completed by 1/1/81. In discussing alternatives to the Shift Technical Advisor, the two principal functions intended to be accomplished and the characteristics thought to be necessary to effectively accomplish these functions were further defined.

(a) Accident Assessment Function

-- The tentative training and education requirements were explained.

-- The need for the S.T.A. to be detached and independent of operations and commerical pressures was emphasized.

-- The need for the S.T.A. to be within ten minutes of the control room was first introduced.

(b) Operating Experience Assessment Function

-- The need for the individuals performing the function to possess the same independence from operations and commercial pressures as the S.T.A. was emphasized.

-- The need for the group performing this function to possess a diverse technical knowledge base encompassing all areas important to safety was defined.

(3) By letter to all licensees dated 10/30/79, clarification of the requirements for the S.T.A. position were issued. Included in these clarifications were the following key points.

(a) The responsibility to perform the two defined functions of the S.T.A. could be split, if it could be demonstrated the persons assigned the accident assessment function were aware, on a current basis, of the work being done by those reviewing operating experience.

(b) To assure that the S.T.A. would be dedicated to concern for plant safety, the assigned individuals must have a clear measure of independence from duties associated with the commerical operations of the plant. Further, "it is not acceptable to assign a person, who is normally the immediate supervisor of the shift supervisor to S.T.A. duties..."

(4) By confirmatory order dated 2/11/80, the licensee was ordered to establish and man the S.T.A. position within 90 days.

(5) By letter to all licensees dated 9/5/80, NRC confirmed the require ments of the 10/30/79 letter.

(6) The licensee's Administrative Directive No. OAD-9 describes the structure of the Operations Subsection, its functioning and the duties and responsibilities of assigned personnel.

(a) Paragraph 2.0 established the Chief Operations Engineer as the immediate supervisor of the Senior Watch Supervisor, the licensee's position title for a shift supervisor.

(b) Paragraph 6.5 establishes the responsibilities and authorities of the S.T.A. as:

-- To be on shift at all times within 10 minutes of the Control Room;

-- To act as an advisor to the Senior Watch Supervisor regarding the safe operation of the plant during acciden conditions; and,

-- To at no time be responsible for the manipulation of reactor controls.

(c) Paragraph 7.4 establishes the major job functions and responsibilities of the S.T.A. as:

-- To act as an advisor to operations personnel;

-- To provide technical and analytical support to the Senior Watch Supervisor;

-- To review logs and records;

-- To review and evaluate day to day operations from a safety point of view;

-- To review and evaluate operating experience;

-- To review and evaluate operating experience of plants of similar design;

-- To provide evaluation of plant conditions required for maintenance and testing;

-- To provide evaluations of the adequacy of procedures;

-- To coordinate activities during major outages; and,

-- To continuously expand their technical knowledge and operational experience.

c. <u>Results of Investigation</u>

The licensee has hired and is in the process of training eight individuals for the S.T.A. position. The S.T.A. trainees function as qualified S.T.A.s during weekend and back shifts. Weekday S.T.A. shift coverage is provided by other licensee personnel, reportedly satisfying S.T.A. training and education requirements. S.T.A. trainee instruction is conducted in the classroom and simulator during weekday sessions. Formal training requirements for the S.T.A. trainees were scheduled to be completed on 11/21/80. No attempt was made during this investigation to determine the acceptability of the educational background or training of the assigned S.T.A.'s.

Interviews of the S.T.A.'s, on shift from 11:00 p.m. on 10/16/80 to 7:00 a.m. on 10/20/80, and others indicate:

-- That each S.T.A. is knowledgeable of his OAD-9 assigned responsibilities, authorities and job functions;

-- That shift relief between S.T.A.'s is performed without benefit of logs or turnover sheets;

-- That a significant part of the S.T.A.'s time is currently spent in furthering their training;

-- That S.T.A.'s are not always called to the Control Room when problems are identified;

-- That the S.T.A.s' lack of confidence in their own knowledge and abilities compounded by the same lack of confidence in the S.T.A.'s by operations personnel, has prevented the realization of the, full potential for safety improvement expected from the S.T.A.'s (reportedly this situation is improving);

-- That the S.T.A.s' sense of responsibility to remain within ten minutes of the Control Room or for reviewing plant conditions to verify the plant is safe, diminishes significantly once the plant is shutdown;

-- That operations personnel will utilize S.T.A.'s for routine activities not involving engineering review or evaluation of plant safety, once the plant is shutdown;

-- That each S.T.A. was aware during his shift(s) that maintenance was repairing leaks on the Fan Cooler Units;

-- That some S.T.A.'s were aware, during their shifts, that water had been found in the Reactor Vessel Pit, but that none had a feel or concern for the quantity of water, that the Vessel might be wetted, or that the Incore Instrument Conduits might be subject to Chloride Stress Corrosion; and,

-- That none had, on their shift, evaluated the propriety of a return to power when it occurred twice on 10/17/80 and once on 10/20/80.

Further, it was learned the Chief Operations Engineer acted as the S.T.A. on Friday, 10/16/80, from 7:00 a.m. to 3:00 p.m. Since the Chief Operations Engineer is the immediate supervisor of the Senior Watch Supervisor, this is a violation of the 10/30/79 criteria for the S.T.A.; specifically, that it is unacceptable that the immediate supervisor of the shift supervisor be assigned as the S.T.A. This last fact is an item of noncompliance (50-247/80-19-02).

d. Recommendation

Of particular concern to the investigators was the apparent acceptance by everyone interviewed, that a timely, detached and independent evaluation of off-normal conditions was not required if the plant was now shutdown or the trip did not result in obvious indicators of an accident condition.

The investigation team recommends that each licensee be required to maintain the S.T.A. position in all modes of operation, including refueling and cold shutdown, with specific prohibitions against the use of S.T.A.'s for other duties supporting Plant operations while on shift.

e. Unresolved Items

Based on the investigation's limited event oriented review of the performance and activities of the S.T.A., a comprehensive conclusion as to the adequacy of the licensee's overall S.T.A. program could not be drawn. The licensee is committed to provide to the NRC, by 12/22/80 a comprehensive "Shift Technical Advisor Performance and Activities Evaluation Report," which will:

(1) Provide an assessment of the adequacy of the performance and activities of the Shift Technical Advisor, on shift from 11:00 p.m. on 10/16/80 to 3:00 p.m. on 10/20/80, as compared to licensee directives;

(2) Provide an assessment of the adequacy of licensee directives as compared to NRC philosophies defined in documents received prior to 10/16/80; and,

(3) Provide a description of changes planned in the use of the Shift Technical Advisors.

This item (50-247/80-19-03) is unresolved.

6. Reporting

a. References

-- 10 CFR 50.72, Notification of Significant Events

-- Technical Specification (T.S.s) Section 6.9.1.7, Reportable Occurrences

-- SAO-125, Indian Point Station, Station Administrative Order No. 125, Revision 2, Station Reporting Requirements

-- SAO-124, Indian Point Station, Station Administrative Order No. 124, Revision 8, Reporting of Anomalous Conditions

-- Memorandum, Chief Operations Engineer to All SWs's, SRO's, RO's, dated 3/6/80, titled "Notification of Significant Events"

-- Significant Occurrence Reports, SOR #80-162 through #80-179

b. Requirements

(1) 10 CFR 50.72(a) requires each licensee of a nuclear power reactor" ...shall notify the NRC Operations Center as soon as possible and in all cases within one hour by telephone of..."

(3) Any event that results in the nuclear power plant not being in a controlled or expected condition while operating or shut down...(and)

(7) Any event resulting in manual or automatic actuation of Engineered Safety Features, including the Reactor Protection System..."

(2) T.S. 6.9.1.7.1 requires the licensee to report by telephone within 24 hours of identification, and confirm in writing, to the Director of Region I or his designate no later than the first working day following identification, the following events:

"(c) Abnormal degradation discovered in fuel cladding, reactor coolant pressure boundary, or primary containment";

"(e) Failure or malfunction of one or more components which prevent, or could prevent, by itself, the fulfillment of the functional requirements of system(s) used to cope with accidents analyzed in the FSAR"; and,

"(i) Performance of structures, systems, or components that require remedial action or corrective measures to prevent operation in a manner less conservative than assumed in the accident analyses in the FSAR or technical specification bases; or discovery during plant life of conditions not specifically considered in the safety analyses report or technical specifications that require remedial action or corrective measures to prevent the existence or development of an unsafe condition."

(3) SAO-125, Revision 2, requires "the Technical Engineering Director shall assure that the NRC is notified in accordance with the Technical Specifications and SAO-124."

(4) SAO-124, Revision 8, requires:

"...the Senior Watch Supervisor to perform the required notifications of 10 CFR 50.72,...and,

"...the Chief Operations Engineer to notify the Technical Engineering Subsection upon identification of a Technical Specification Reportable Occurrence, and the Technical Engineering Subsection to notify the NRC, as appropriate."

(5) Licensee's Memo dated 3/6/80, requires the NRC Resident Inspector be notified of significant events at his office, or if unavailable, at his home.

c. Results of Investigation

(1) The licensee documented the 10/17/80 failure of Nuclear Instrument Channel N42 on SOR #80-174. The S.W.S. recommended the event be reportable under Technical Specification requirements for 30 day notifications. The C.O.E. and T.E.D. concurred in this recommendation on 10/18/80 and 10/22/80, respectively.

(2) The licensee documented the Turbine runback and the first 10/17/80 Reactor trip on SOR #80-175 and SOR 80-176, respectively. The S.W.S. recommended the runback not be reportable. The S.W.S. recommended the Reactor trip be reportable under 10 CFR 50.72, and informed the NRC Duty Officer of both the runback and the trip within one hour of each events occurrence. Neither the C.O.E. or T.E.D took exception to the S.W.S.'s recommendations, during their documented review on 10/18/80 and 10/22/80, respectively. The T.E.D. notified the NRC Resident Inspector of the events of the morning at about 8:30 AM on 10/17/80.

(3) The licensee documented the second 10/17/80 Reactor trip on SOR #80-177. The S.W.S. recommended the trip be reported under 10 CFR 50.72, and informed the NRC Duty Officer of the trip within one hour of the event. The event was reviewed by the C.O.E. and T.E.D on 10/17/80 and the review documented on 10/24/80, with no exceptions taken to the S.W.S.'s recommendation. The T.E.D. discussed the second Reactor trip with the NRC Resident Inspector at about 9:30 AM on 10/17/80.

(4) The licensee documented the 10/17/80 discovery of water on the Vapor Containment Floor, F.C.U. leakage, and Sump Pump failures on SOR #80-178. The S.W.S. recommended the event be reportable under Technical Specification requirements for 30 day notification. The C.O.E. reviewed the SOR on 10/18/80 and did not take exception to the recommendation. The T.E.D. determined in his review on 10/22/80, that the event was not reportable in itself, but only as a result of its significance in the failure of the Nuclear Instrument Channel N42.

Although the Vapor Containment Floor routinely has wet areas, due to leaks and the dumping of Fan Cooler Unit condensate on the floor, the floor troughs, sump and Vapor Containment Sump Pumps normally keep the majority of the floor dry. The flooded condition of the Vapor Containment Floor was not expected, as evidenced by the need of the initial Vapor Containment entry team to add rubber boots to their anti-contamination clothing, before attempting a second entry. The licensee's failure to report the discovery of this event (the simultaneous presence of multiple Fan Cooler Unit leaks and the existence of an inoperable condition of both Vapor Containment Sump Pumps), which lead to the unexpected condition (major flooding of the Vapor Containment Floor), to the NRC Operations Center within one hour (by 2:30 P.M. on 10/17/80), is a noncompliance with 10 CFR 50.72(a)(2).

Although Fan Cooler Unit leaks were common, the number and volume of the leaks discovered on 10/17/80 cannot be considered normal. Eyewitness accounts of the flow from at least 4 Fan Cooler Unit Weirs, describe the flow appearance from each as that from a garden hose. That the licensee recognized the importance of fixing these leaks is indicated by the direction to plant operator to restart the plant after the leaks were repaired and the Reactor Vessel Pit dry. The licensee's failure to promptly report to NRC within 24 hours (by 10/18/80), the abnormal degradation discovered in primary containment (the Fan Cooler Unit Cooling Coils and Service Water Piping), is a noncompliance with T.S. 6.9.1.7.1.c.

The fortunate discovery on 10/17/80 of the leakage from the Fan Cooler Unit Service Water System and the presence of a large accumulation of water (about 100,000 gallons) on the Vapor Containment Floor, invalidated design assumptions of the flooding level expected in the Vapor Containment during a Design Basis Loss of Coolant Accident. Had the licensee not chosen to shutdown to make a Vapor Containment entry on 10/17/80, to repair the failed Nuclear Instrument Channel Detector, the water accumulating in the Vapor Containment Floor and, as a result the potential accident water level, could have gone much higher before the plant would have been forced to shutdown. The resulting accident water level had the potential for preventing the Recirculation System from fulfillment of its functional requirements by flooding out the Recirculation Pumps located in the Vapor Containment. The licensee's failure to promptly report to NRC within 24 hours (by 10/18/80), the multiple failures of the Fan Cooler Unit Service Water System pressure boundary and the inoperability of the Vapor Containment Sump Pumps, which could have prevented by themselves the fulfillment of the functional requirements of the Recirculation System during a Design Basis Loss of Coolant Accident is a noncompliance with T.S. 6.9.1.7.1.e.

(5) The licensee documented the 10/17/80 discovery of the failure of Main Steam Isolation Valve, MS-1-23, to close automatically on SOR #80-179. The S.W.S. recommended the event be reportable under Technical Specification requirements for 30 day notification. Neither the C.O.E. or T.E.D. took exception to the recommendation during their review on 10/18/80 and 10/22/80, respectively.

The T.E.D. intended to inform the NRC Resident Inspector of the failure of the M.S.I.V. and the discovery of some water on the

Vapor Containment floor, when he tried to contact the Resident at about 3:20 P.M. on 10/17/80. When he was unsuccessful in establishing that contact, he left a message on the Residence's answering machine, requesting a return call. Since the Resident had already left the site, with express permission of his supervision, that return call was not made until the morning of 10/20/80. The T.E.D. finally reestablished contact with the NRC Resident Inspector about 11:30 A.M. on 10/20/80, when the information then known by the T.E.D. was discussed.

(6) The discovery, during the evening of 10/17/80, that the Reactor Vessel Pit had been flooded to within four feet of the elevation 46 feet floor, was not documented by the licensee during the 10/17-20/80 weekend. This flooding elevation in the Pit corresponded to a water level on the outside of the Reactor Vessel itself of about 8½ feet. The submergence of the Reactor Vessel and the Incore Instrument Conduits in cold, high chlorides, River Water, while at normal operating temperatures of about 550°F, is a condition not considered in the safety analysis report or technical specifications and did require corrective measures, the removal of the water and boildown residue plus nondestructive examinations of the Reactor Vessel and the Conduits, to prevent the development of an unsafe condition. The licensee's failure to promptly report to NRC within 24 hours (by 10/18/80) the discovery of the flooded Reactor Vessel Pit is a noncompliance with T.S. 6.9.1.7.1.i.

d. Conclusion

The three noncompliances documented above, each explain why the licensee should have promptly reported the Vapor Containment flooding event. Since each is only example of the rationale the licensee could have used to report the basic event, the three are combined into a single item of noncompliance with three examples (50-247/80-19-04).

7. Reactor Trips and Instrumentation

a. General

The inspector held discussions with key plant personnel and reviewed operating logs to determine the cause of the two Reactor trips, which occurred on October 17, 1980.

b. Turbine Runback

At 12:30 a.m. on October 17, 1980, a control room operater noticed the Nuclear Instrumentation (NI's) Channel readings did not appear normal. This was discovered while performing the daily heat balance. A quadrant power calculation was performed to assure power distribution was correct. The calculation produced two apparent abnormalities; 1) the quadrant tilt was 1.0240 at the top of the Core and 1.0363 at the bottom (Technical Specifications limits the quadrant tilt value to 1.02); and, 2) power appeared to be excessive in the top of the Core in the Channel N42 quadrant. At this point, the operators began to plot axial tilts.

The Turbine load was decreased to reduce Reactor power, in an attempt to reduce the quadrant power tilt, and Reactor power was stabilized at 90 percent. The operators suspected Channel N42 was failing. I&C personnel on site were requested to perform a functional test of the Channel. The Reactor Engineer was called to the site and an incore flux map was obtained. After a review of the incore flux map, the Reactor Engineer declared Channel N42 inoperable. The operators then obtained the Emergency Procedure for Nuclear Instrumentation Malfunction, assumed the Channel had already failed, and proceeded to perform the "Subsequent Action" portion of the procedure, without first verifying the "Immediate Operator Action" portion of the procedure had been satisfied. Had the operators performed the required immediate action, they would have reduced power below 70 percent power before deenergizing the channel. When the Control Power fuses were pulled by procedure, the rapid decrease of indicated power on Channel N42 appeared to the protection system as a dropped rod, and caused a Turbine runback to 70 percent power.

c. First Reactor Trip

The Control Rods were being operated manually and did not step in automatically during the Turbine runback. The existing Core axial flux distribution was now outside its program band. Average coolant temperature (Tavg) began increasing with the load/power generation mismatch. The use of Control Rods to correct the Tavg problem would have further aggravated the Core axial flux distribution problem. It was decided to increase the Turbine load to correct both the Tavg and flux distribution problems.

The governor valves on the Turbine were closed to a controlling position from the control room, taking control of the Turbine away from the load limiting valves, which were holding power at 70 percent. Communication was set up between the Control Room and a Nuclear Plant Operator (NPO), who had previously been instructed on how to perform the evolution of opening the load limiting valves. The NPO turned the valves in the wrong direction as a result of a combination of human and communication errors. This caused a rapid decrease in Turbine load, causing a momentary shrink in the Steam Generators water level and an increase in Pressurizer pressure, resulting in either a LoLo Steam Generator water level or Hi Pressurizer pressure trip of the Reactor.

d. Second Reactor Trip

The Reactor was subsequently made critical by normal start up procedures and the power level was maintained at about 3 percent. I&C technicians were performing response checks on NI Channel N42. The I&C supervisor noted a sluggish response from the lower detector of Channel N42. Channel N42 was then placed back in service to conduct a comparision response check of Channel N41. All trip functions were restored on Channel N42, with the exception of overpower delta "T" and overtemperature delta "T"; these functions were left in a tripped condition. The supervisor believed there was no danger of lowering the overpower or overtemperature delta "T" trip setpoints, sufficiently to cause a Reactor trip at the existing power level, while the response checks were being performed. When the comparison check on Channel N41 lower detector was attempted, the overpower delta "T" trip setpoint was reduced to the point at which a trip occurred. The simultaneous existence of Channels N41 and N42 overpower delta "T" trip signals satisfied the Reactor Protection Systems 2 out of 4 logic, causing a Reactor Trip.

On 10/17/80, the signal produced by the lower Detector of Channel N42 became erratic. The licensee's investigation concluded the Detector or its cable were grounded. The ground was later attributed, on 10/21/80 to moisture found in the Detector connector. An I&C supervisor concluded that the moisture was a result of operation in a steam vapor environment for which the connector was not designed. The Nuclear Instrument connectors are not water tight, but are wrapped with electric tape by technicians, to prevent the metal parts from grounding to their metal lined container. No attempt is made by the licensee to make the connections moisture proof. The procedure for installation of a new Nuclear Instrument Detector does not require taping.

e. Nuclear Instrument Channel N42

The Nuclear Instrument Detectors are located on the outside of the Reactor Vessel, in movable Detector holders that facilitate Detector removal and repair.

f. Findings

Technical Specification 6.8.1 requires procedures be followed. The operators' failure to implement the Immediate Operator Action requirement to reduce power to at or below 70 percent, prior to pulling the control power fuses, is an item of noncompliance (50-247/80-19-05).

g. Unresolved Items

At the completion of the on site investigation, it was determined that additional information relative to the trips and performance of instrumentation, were required. The licensee has committed to providing the following documents by 12/22/80:

(1) Reactor Trip Cause Identification System Evaluation Report

-- explaining why the plant computer identified the first 10/17/80 Reactor trip cause as high Pressurizer pressure, while the first out annunciator identified the trip cause as low Steam Generator water level; and,

-- providing rationale for acceptance of this discrepancy or describing how the systems will be upgraded to resolve the problem.

This item (50-247/80-19-06) is unresolved.

(2) Excore Nuclear Instrumentation Evaluation Report

-- providing a description of tests and inspections performed and the results achieved for the excore nuclear instrumentation, following the flooding event;

-- discussing the probable impact on the instrumentation life and reliability; and,

-- justifying continued operation without repair or modifications.

This item (50-247/80-19-07) is unresolved.

(3) Immediate Action Letter No. 80-41 Report

-- providing response required by item (8) of the Immediate Action Letter.

This item (50-247/80-19-08) is unresolved.

8. Containment Sump Pumps and Sump Level Measurement

a. Water Collection

General leakage from fluid systems and condensation in containment collects on the containment floor at elevation 46. The floor is sloped in various directions so that fluids run into troughs and then into the containment sump. The reactor vessel pit is protected from water on the floor by a 6 inch curb. The containment sump is automatically pumped by two Sump Pumps to the Waste Hold Up Tank (WHUT) outside of containment. The WHUT receives liquid waste from many sources in Unit 2 and is in turn sent to the Unit 1 radioactive waste processing systems. The containment sump is about 7 and one-half feet or 90 inches deep.

b. Sump Level Measurement

(1) Description

Containment Sump Level is measured by 10 Gem type, magnetic reed, float switches on two float rods. These switches read out in the control room and are labeled: 1", 7", 45", 51", 91", 97", 139", 145", 151" and 159". Their zero reference is several inches from the bottom of the sump and they are not precisely located in accordance with their inch markings. The general belief among operators, prior to October 17, 1980, was that the 91" light indicated a sump level about an inch or two below the top of the sump. In fact, the 91" float was a few inches above the top of the sump, i.e., the containment floor, but below top of the curb surrounding the reactor vessel pit. Normal sump level varied from above the 7" light to around the 51" light. Prior to October 17, 1980, the sump pumps appear to have cycled-on just above the 51" light and to have pumped the sump down to between the 7" and 45" lights.

There were normally several days between the times that the sump pumps operated. The control room operators log the sump level based on these lights every 4 hours. The log sheets state that the normal reading is greater than or equal to 7". The sump level lights are checked each refueling and were last tested on June 18, 1979.

(2) Performance

Prior to October 3, 1980, indicated sump level had been at 45" for a few days and there were some questions raised by the operators as to whether the sump level lights were operating properly. During a containment entry made on October 3, 1980 to correct an FCU service water leak, the Chief Operations Engineer operated several of the float level switches and containment sump pump #210. The control room later said they saw the level lights flash and the Chief Operations Engineer stated that the sump pump appeared to operate properly. After this entry and until October 17, 1980 the sump level was logged at 51". The 91" light reportedly never came on. This could have been caused by: (a) stuck float switches, (b) a true level just above 51" but below the pump cycle-on point, combined with essentially zero collection in the sump, and/or (c) a true level above 51" and increasing, combined with no sump pump operation. After the plant shutdown on October 17, 1980, the 45", 51" and 91" float switches were operated and the control room lights appeared to operate correctly. During the five months previous to October, 1980, the combination of leakage and condensation going into the sump had never been low enough so that the 51" light remained on long enough to coincide with and to be logged during one of the 6 daily log reading periods. This combination of information supports choice (c) above.

(3) Modifications

One of the recently imposed requirements from the Three Mile Island Lessons Learned Study was for continuous indication in the control room of containment water level, both narrow range and wide range, from the bottom of the containment sump and reactor vessel pit. This was classified as a Category B item, which required implementation by January 1, 1981. The licensee had committed to this requirement and had not yet installed the continuous indicators. Current plans are to install these continuous level indicators both in the containment sump and reactor vessel pit. Details of the modifications will be submitted to NRC by December 22, 1980 and are considered unresolved (Item No. 50-247/80-19-09).

After October 25, 1980, the licensee reset the containment sump pump cycle points so that sump level is maintained between the 7" and 45" lights. Control room annunciators were attached to the 45" and 51" switches and all lights above 45" were changed in color to highlight their significance.

(4) Additional Open Items

Technical Specification 6.8.1 and ANSI N18.7-1972 require that procedures be established to provide an approved, preplanned method of conducting operations. These documents also state that limitations on parameters being controlled and appropriate corrective measures to return the parameter to the normal control band should be specified. Contrary to the above, procedures were not established which would provide for a preplanned method of controlling containment sump level. Specifically, no control band (other than $\geq$7 inches) or maximum sump level was specified, nor were corrective measures for high sump levels detailed. This is an item of noncompliance and is designated Item No. (50-247/80-19-10).

The acceptability of the arrangement of the sump level measurement system is unresolved, due to:

(a) no warning just prior to overflowing the sump, and

(b) level markings which do not correspond to actual levels and which cause operator confusion.

This item is unresolved and is designated Item No. (50-247/80-19-11).

c. Containment Sump Pumps

(1) Description

There are two sump pumps located in the containment sump, #29 and #210. They are Goulds Vertical Sump Pumps, Model 3171 rated at 50 gallons per minute (gpm) each. The motor control center, circuit breakers and pump control switches are located inside containment. There are no controls or direct indications of pump operation outside of containment. The pumps operate automatically using a float ball and switch arrangement. The pumps are tested for operation each refueling outage and were last tested June 18, 1979.

(2) Performance

Sometime prior to October 17, 1980, both containment sump pumps failed to pump when their actuation levels were reached. During containment entries on October 17, 1980, pump #210 was found to have its float rod cocked and stuck in the sump grating. When straightened, the pump started. The fuses of pump #29 were replaced, the thermal overload reset button was pushed and the circuit breaker closed. This pump then started. Several times during the time period October 17 through October 19, 1980, the sump pump float rods and/or float balls were found to be inoperable and were repaired.

One reactor cavity sump pump is powered from downstream of the fuses for containment sump pump #29. It appears that failure of the reactor cavity pump due to overheating at sometime prior to October 17, 1980, caused the fuses for containment sump pump #29 to blow, also.

The licensee has committed to provide the NRC with a detailed failure analysis report on the containment sump pumps by December 22, 1980, which will:

sensitivity is on the order of 0.25 gpm per degree Fahrenheit (^{o}F) of dewpoint temperature increase. Procedure SOP 1.7, "Reactor Coolant System Leakage Surveillance and Safety Evaluation" performs leakage calculations daily using various means, including the containment humidity detectors. Additionally, the highest and lowest of the 5 dewpoints is recorded every 4 hours on the control room logs.

(2) Performance

During the two weeks prior to October 18, 1980, the dewpoint detectors were reading as they previously had, namely at or below the bottom of the multipoint recorder's scale, which is 70^{o}F. No response would be expected to the leak of the cold Service Water into containment. On October 18 and October 19, 1980, the dewpoints varied up and down to a maximum of about 88^{o}F, apparently in response to the steam generator blowdown line leak, the steaming of water in the reactor vessel pit while in contact with the reactor vessel, and the operation of different numbers of FCU's. Calibrations performed on 10/25/80 showed that the dewpoint instruments were all reading significantly low.

Based on the above, the response and the calibration interval adequacy of the humidity detection system is unacceptable. The licensee has committed to submit a report on this issued by December 22, 1980, which will do the following:

-- explain the cause of each change in the trend of average dewpoint recordings for the period 11:00 p.m. on 10/16/80 to 3:00 p.m. on 10/20/80;

-- incorporate best estimates of steam generator blowdown line leak flow, start time, containment mixing and stop time;

-- incorporate best estimates of fan cooler unit operations including number in operation versus time, moisture removal capability and service water temperature;

-- incorporate best estimates of reactor vessel water level versus time, steaming rates, containment mixing and location of instrumentation versus source of steam;

-- justify continued operation with a recorder lower limit of 70^{o}F;

-- justify current surveillance frequency which allowed the instruments to become so out of calibration; and,

-- explain why reactor vessel steaming was not detected.

This item is unresolved (Item No. 50-247/80-19-27).

(3) Modifications

Reportedly, no modifications are currently planned for the humidity detection system. A report will be submitted to the NRC which will justify operation with the system as is. The item is unresolv pending submission and review of the report and is designated as Item No. (50-247/80-19-28).

(4) Additional Open Items

Technical Specification (T.S.) 6.8.1 and Regulatory Guide 1.33, Appendix A, paragraphs F.1 and H.2, require procedures be established and implemented for each surveillance required in the Technical Specification. Contrary to this requirement, procedures were not established to satisfactorily implement T.S. 3.1.F.1 regarding determination of leakage from the reactor coolant system (RCS) with the humidity detection system. Specifically:

(a) The Procedure SOP1.7 action level for dewpoint of 89°F and increasing and the control room log sheet maximum dewpoint of 95°F combined with a normal reading of 70°F or lower corresponded to an already significant RCS leakage (>4 gpm);

(b) The humidity detectors were not sensitive to incremental increases of water leakage as described in the FSAR and T.S. Bases, because they were normally off scale low (less than 70°F) as logged on the control room logs for the majority of September, 1980;

(c) No calibration procedures were established to calibrate or set the alarms for the humidity detectors; and

(d) Graph RCS-8, which is used to quantitatively determine an RCS leak rate based on observed dewpoints, is not accurate, since it apparently assumes a baseline dewpoint near 85°F, while actual baseline values are at or below 70°F.

This item of noncompliance is designated as Item No. (50-247/80-19-29).

11. Fan Cooler Units

a. General

The majority of the water which collected on the Vapor Containment floor was River Water from Service Water leaks on Fan Cooler Unit cooling coils and supply piping. The Fan Cooler Units (F.C.U.s) are the heat exchangers for the Containment Cooling and Filtration System. There are five F.C.U.s, numbered 21-25. Each cooling coil assembly consists of 10 units mounted in two banks, one behind the other and stacked five high for horizontal air flow. The heat exchangers are air conditioner type cooling coils consisting of 90-10 Cu-Ni (pipe) headers, 90-10 Cu-Ni stub tubes (nipples), 90-10 Cu-Ni tubes and copper plate type fins. In addition to the large F.C.U. heat exchangers each Unit has a tube and plate type heat exchanger as a motor cooler. The F.C.U. heat exchanger is hard piped to the service water system and the motor cooler heat exchanger is connected to the system with flexible hoses.

The Service Water System supplies the cooling water for the heat exchangers through carbon steel-cement lined pipe. The cooling water is untreated Hudson River Water. The River Water is routinely analyzed by the licensee's chemistry personnel. As with any tidal dynamic river, the chemical composition of the river is affected by upstream and downstream effluents. Due to a recent drought, salt water intrusion has significantly raised the Chloride ion content of the river. A review of the licensee's River Water analysis for the week ending 10/22/80 indicated, in part, a 7.5 - 7.9 pH and 4560 -4600 ppm NaCl chlorides.

b. Leaks

The F.C.U. Service Water leaks can be divided into the following categories:

(1) Localized failure of cement lined carbon steel pipe. This failure mode has been limited to localized general corrosion failures at welded joints, due most probably to improper fit up linings or damage to the lining caused by field welding, possibly accelerated by small anode (Fe) to large cathode (Cu-Ni) galvanic effects.

(2) Stub tube (nipple) to header joint leaks. No information is available to indicate whether the failure mode is related to corrosion or to improper brazed joints (manufacturing defect).

(3) Stub tube on Heat Exchanger tube leaks. No information is available to indicated whether these failures are related to low velocity induced pitting, high velocity erosion, or propagation of incipient tube defects.

(4) Flexible hose failures on the Motor Cooler Heat Exchanger. There is no information available to indicate whether these failures are caused by fatigue or corrosion, however, the most probable cause is fatigue.

c. F.C.U. Status and Maintenance History

The NRC inspector held discussions with site maintenance and corporate engineering personnel to determine if specific failure analysis studies were made on any of the F.C.U. related leaks. No failure analysis has been conducted by the licensee, other than those conducted on cement lined pipe failures. (This deficiency is discussed further under QA/QC Program).

The maintenance records for the fan coolers were reviewed with the Maintenance Engineer. The general maintenance history was discussed with the Assistant Vice President for Engineering and cognizant engineering personnel selected by him. A discussion was held with the Maintenance Engineer following his detailed inspection of the F.C.U.s. Later the NRC inspector conducted a thorough visual inspection of the F.C.U.s, accompanied by the Maintenance Engineer. The report of observations by the Maintenance Engineer of the five F.C.U.s on 10/26/81 indicated 46 previous repair locations (reported in 32 MWR's), and 8-12 current probable leaks. There were 7 currently installed pipe clamps, 8 re-brazed repairs and 18-25 epoxy repairs noted. The 18-25 number results from difficulty identifying general repaired areas as individual or group repairs. A Maintenance Department summary sheet made up from Maintenance Work Request (MWR) records indicates 3 repairs on F.C.U. #21, 3 on F.C.U. #22, 9 on F.C.U. #23, 7 on F.C.U. #24 and 10 on F.C.U. #25. The total of 32 "MWR repairs" includes some multiple repairs conducted under one MWR. The failure rate of the F.C.U.s, due to leaks, is presented on attached Figure 4, in the form of a histogram.

Review of the header/stub tube/heat exchanger tube design by the NRC inspector reaffirmed the licensee's opinion of the difficulty in accomplishing effective repairs to the heat exchanger. The all-brazed design combined with the close spacing of the tubes and relative thickness of tubes and headers (0.035"/0.154-0.237"), makes localized re-brazing almost impossible. (Fix one joint and damage the braze on the adjacent tube joint.) The Maintenance Department first attempted re-brazing of the Cu-Ni materials to repair a leak. This was marginally successful along the length of the tubes, but unsuccessful at the header/stub end joints. The only successful leak repair utilized was a "temporary fix" with epoxy resins and fiber glass tape.

Leaks in large diameter cement lined pipes were temporarily repaired with "Adam's Clamps" (rubber gaskets clamped over the leak). Leaks in small diameter pipe sections were repaired with "Adam's Clamps" or by replacement with austentic stainless steel pipe. The Engineering Department indicated that the life of a "temporary fix" was 1 to 3 years.

d. Service Water System

A walk down inspection was made of the observable portions of the service water piping providing cooling water for the F.C.U.s from the 6 Service Water Pumps and their Traveling Screens to the piping penetrations outside of the Vapor Containment. The piping system is cement lined pipe up to the F.C.U. heat exchangers, where the piping is then Cu-Ni. Review of maintenance records and visual observations indicated minimal problems in the large diameter cement lined piping system outside the Vapor Containment. It was reported to the NRC inspector that there have been problems in the piping system associated with localized high velocity (design related) erosion. These problems which occurred early in service life, resulted in installation of stainless steel dutchman sections, in the piping system outside the Vapor Containment.

e. Heat Exchangers

A review was made of maintenance records for the subject heat exchangers The purpose of the review was to obtain, if possible, a categorization of the failures in these heat exchangers associated with the Service Water cooling system. Equipment failures not related to the Service Water cooling system were not evaluated. Difficulty was encountered in analysis of the maintenance files, due to lack of explicit information on location of failures and repair technique details. Maintenance files were fortunately segregated by Fan Cooler Unit. The results of this cursory analysis by the NRC inspector are shown on attached Figure 6.

f. Meeting With The Licensee Regarding Fan Cooler Unit Heat Exchangers

On October 28, 1980, the NRC Corrosion and Metallurgy Specialist met with members of the licensee's engineering staff. The purpose of the meeting was to discuss the F.C.U. Heat Exchangers (and related parts of Service Water Cooling System) at Indian Point 2. The following information was obtained.

(1) Indian Point 2 (IP2) operation started in 1973-74, so the F.U.C.'s have seen approximately 6 1/2 years (interrupted) service.

(2) In February 1979, corporate engineering started to review the repair procedures utilized, i.e., the EPI SEAL tube plugging procedure.

(3) IP2 had requested corporate engineering to review the adequacy of the EPI SEAL procedure for temporary repairs.

(4) A temporary repair was described as a repair capable of 1-3 years satisfactory service.

(5) Corporate engineering set up a program to evaluate the EPI SEAL (epoxy) system in a steam environment.

(6) The evaluation consisted of applying a band of epoxy on a straight length of unfinned 90-10 Cu-Ni tube, curing at 80°F and 120°F, emersing in a steam bath for 24 hours at 212°F, and attempting removal of the epoxy band by mechanical means. The results of the test indicated satisfactory adherence to the tubing. Tests were not run with fiberglass tape saturated EPI SEAL, nor were tests run on a "plugged end" technique repair.

(7) Corporate engineering reviewed a rebrazing repair technique for repair of the brazed nipple failures. This procedure would consist of cutting a "window" in the header and attempting to rebraze the nipple to header joints, then rebrazing the "window" back onto the header. Investigation indicated this repair procedure was unreliable, due to proximity of other nipples, inability to properly clean, and other difficulties meeting adequate brazing requirements.

(8) Corporate engineering indicated that the headers were all Schedule standard pipe dimensions. They indicated that there were approximately 630 "U" tubes (brazed return heads) per Fan Cooler Heat Exchanger and that the manufacturer (Westinghouse) indicated that only 8 tubes could be plugged per Heat Exchanger (1.27%), without compromising the required heat transfer requirements.

(9) In December 1979, corporate engineering made an engineering decision to replace all of the Heat Exchangers (a maximum of 2 Heat Exchangers would be replaced in one regular refueling outage).

(10) A specification for new improved design Heat Exchanger has been prepared and is going through the sign off procedure. The proposed new design will utilize a rectangular cross section header with a removable cover for tube plugging purposes (A purchase order had not been placed for the revised design Heat Exchanger at the time of the meeting).

(11) Corporate engineering indicated the corrosion service behavior for other 90-10 Cu-Ni HX tubes, seeing the same service water, i.e., turbine oil coolers, lube oil coolers, inner and after condensers, hydrogen coolers, etc., has been determined to be

excellent. (It should be noted that the main surface condenser is not 90-10 Cu-Ni, but rather Silicon bronze tube sheets, Admiralty tubes, and tubes welded to the tube sheets. The service performance of the Admiralty tubes has not been excellent and currently 90-10 Cu-Ni, (AL)6X, and 904L sample tubes are being evaluated. It is reported that the 90-10 Cu-Ni tubes in the condenser "look very good".)

(12) Corporate engineering indicated that the operating procedures for the fan coolers do not include prolonged stagnant wet layup.

(13) Corporate engineering indicated that no specific failure analysis evaluations have been made on portions of failed tubing or pipe from the fan coolers.

g. Motor Cooler Hose Repair

A detailed analysis was made of the MWR 4156, which was written for the replacement of a failed motor cooler flexible hose. This MWR indicated the original hose was replaced with one fabricated of austentic stainless steel. The technique employed, retained intact the original flexible hose to 90-10 Cu-Ni pipe dissimilar metal weld. As it was believed by the licensee that the alloy composition of the original flexible hoses was austentic stainless steel, a 2" stub section on either end of the original hose has retained and prepped for welding to permit a stainless steel to stainless steel weld. The welding was performed using a stainless steel to stainless steel tungsten arc welding procedure, and austentic stainless steel steel filler metal. Review of the drawings and drawing changes for the flexible hose by the NRC inspector, indicated the original flexible hose was specified as Ni-Cu Alloy 400, then later changed to Ni-Cr-Fe Alloy 625. The weld history records confirm that the weld was made with a stainless steel to stainless steel welding procedure and with steel filler metal. The records also indicate that the finished weld was dye penetrant tested successfully.

Due to the confusion on the alloy composition of the flexible hoses the licensee conducted chemical spot identification tests on the existing flexible hoses.

A standard test with a known alloy (316) was utilized to indicate adequate activity for the reagents. The test was successful in producing the proper colorometric results. Another repeat test was run on a known sample of Ni-Cu Alloy 400 with radically different colorometric results. The NRC inspector witnessed these colorometric results. Discussions with the licensee indicated that tests were conducted on all 10 installed flexible hoses, and indicated the results positively identified the installed flexible hoses to be chromium bearing materials

These results and other characteristics indicated the installed flexibl hoses were not Alloy 400, which contains no chromium. The licensee later determined that the original flexible hoses were neither Alloy 400 or austenitic stainless steel, but rather, Ni-Cr-Fe Alloy 625.

The licensee's approved QA Program commits him to the requirements of 10 CFR 50, Appendix B. Appendix B, Criterion VIII requires that "measures shall be established for the identification and control of materials,"... and that "...these identification and control measures shall be designed to prevent the use of uncorrect or defective material parts, and components." The inspectors review of records indicates the licensee replaced an Alloy 625 flexible hose with stainless steel flexible hose, without knowledge or engineering concurrence for the change, and then welded the stainless steel hose to Alloy 625 stub tubes, using a procedure not qualified for this dissimilar metal combination. This failure to identify and control materials is an item of noncompliance (50-247/80-19-29).

h. Unresolved Item

Based on NRC concerns expressed to the licensee during a public meeting on November 5, 1980, the licensee has committed to provide the NRC the following report by December 22, 1980.

Fan Cooling Unit Cooling Coil and Service Water Pipe Failure Analysis Report

-- providing a description of tests and inspections performed to identify the cause of failures.

-- detailing the results of the analysis of failures.

-- explaining why the proposed modified or repaired system is immune to the identified failure mechanisms or why these failure mechanisms are now tolerable.

This item (50-247/80-19-30) is unresolved.

12. Reactor Vessel Pit Flooding Analysis

a. General

The initial report of water on the Vapor Containment Floor was received by the NRC Resident Inspector on October 20, 1980. The quantity of water removed from Containment and sent to the waste holdup tank was not then known. Based on concern for the potential consequences of submergence of the Reactor Vessel, it was determined to be necessary to quantify the maximum flooding elevation of the Reactor Vessel Pit.

b. References

The following documents were reviewed:

(1) Indian Point Station, Unit 2, SOP 5.1.2, Rev. 0, Radioactive Liquid Waste Discharge and Transfer Operator

(2) Indian Point Station Support Facilities, Unit No. 1, 0-37.5, Liquid Waste Evaporators, No. 12 and No. 13

(3) Unit 2, Containment Water inventory Calculator Sheet

(4) Waste Collection Tank Level Transmitter Calibration MWR's

(5) Nuclear Area - Log Sheets (Shutdown Conditions)

(6) Waste Collection Tanks Height vs. Volume Sheets

(7) Unit 2, Water Capacity above Reactor Pit, Volume calculation

(8) Work Sheet Water Inventory 10/17 to 10/20

(9) Unit 2, Waste Holdup Tank - Volume curve

(10) Inspector's Preliminary Calibration Sheet

(11) Con Ed Drawing No. A 188852-2

(12) Con Ed Drawing No. A 188851-9

(13) Graver Tank Drawing No. L 18438-6

c. Preliminary Licensee Estimates of Reactor Vessel Pit Flooding

The method used to control liquid radioactive waste at the Indian Point, Unit 2, utilizes the Unit 1 Support Facility's waste evaporation and storage tanks. Following discovery of water on the Vapor Containment floor and the restart of the two Vapor Containment Sump Pumps, all Containment Liquid Effluent was transferred to the Unit 2 waste holdup tank, where, upon reaching a predetermined level, the waste was then transferred to the Unit 1 facility.

The inspector's initial inquiry as to the volume of liquid pumped from the containment yielded an estimate by the licensee of 40,000 to 43,000 gallons. The inspector further requested data on the required volume of liquid necessary to touch the bottom of the Reactor Vessel. Initial calculations performed by the licensee estimated 59,928 gals. of liquid in the Reactor Vessel Pit would be required to bring the water level in contact with the Vessel. Based on the preliminary estimate of 43,000 gals. transferred and approximately 60,000 gals. needed to contact vessel, the licensee determined that water did not touch the Vessel. The inspector requested data to confirm these initial water estimates.

The entrance points of liquid waste into the Reactor Vessel Pit are limited to two defined areas; the Incore Instrument Tube entrance and a locked grating and hatch entrance leading to the Reactor Vessel viewing platform. Both of these areas have a 6 inch curb or lip that should prevent flow from the Vapor Containment Floor, until the floor water level exceeded 6 inches. The amount of water on the Vapor Containment Floor, needed to overflow into the Reactor Vessel Pit, was tentatively estimated by the licensee to be 41,646 gals. Thus, with a preliminary estimate of liquid waste discharges and the water on the Containment Floor needed to overflow into the pit, it was determined by the licensee that only 1354 gallons (43,000-41,646 = 1354) flowed into the pit.

d. Initial N.R.C Observations of Reactor Vessel Pit

On completion of review of the licensee's preliminary water inventory calculations, which on October 21, 1980, appeared to support the assumption that Reactor Vessel was not wetted, the NRC Resident Inspector made direct observations of the Reactor Vessel Pit area. The following items were observed on entry at 1659 hours on 10/21/80.

1) At the foot of the 46 foot level in the Vapor Containment building, small pools of water (1/4 inch to 1/2 inch in depth) were observed.

2) Upon reaching the Reactor Vessel Pit intermediate platform, the permanent lighting was found to be inoperable.

3) By use of a portable light, the following areas were observed and found to have white, salt-like precipitate covering.

   a) The Reactor Vessel Mirror Insulation at the "orange peel" seams.

   b) The Reactor Ventilation Duct encircling the Vessel.

4) No water was observed on top of the ventilation duct.

5) In the Reactor Vessel Pit, the licensee was removing one of the Pit Sump Pumps. The electrical connections to the pump had been previously removed and no judgement as to quality of original electrical hook-up could be made.

Based on observations, but not supported by either the licensee's or the inspector's preliminary water inventory calculations, the inspector concluded that the Reactor Vessel had been wetted.

e) Additional Licensee Estimates of Pit Flooding

On October 22, 1980, an estimate of about 100,000 gals of liquid removed from the Containment was announced. The licensee had determined the earlier estimates to be in error, in that they did not take into account the removal of liquid from the Unit 1 collection tanks during waste processing.

The licensee's new estimates were based on the following calculations and assumptions; corrected total transfer to Unit No. 1 Storage & Processing Tanks (129,110 gallons), minus Unit 1 and Unit 2 normal outside containment leakage (20,042 gallons), minus continued leakage into containment during pumpout (21,600 gallons). This new computed volume pumped from the vapor containment was 129,110 - 41,642 = 87,468. Additional discussions and using more conservative figures for system leakage brought totals to approximately 98,264 gallons waste liquid removed from Containment.

Based on the original estimated floor capacity of 41,646, the amount of liquid in the Reactor Vessel pit was now estimated at 98,264 - 41,646 = 56,618 gallons. This amount would not wet the Reactor Vessel, assuming the licensee's estimate of 59,928 gallons to just touch the Vessel was correct.

f. NRC Reactor Vessel Pit Water Level Observations Curve

An NRC Reactor Vessel Pit Water Level observation curve (Figure 1) was developed by reviewing and evaluating various logs and testimony of individuals with first hand knowledge of the Reactor Vessel Pit water level, observed on their various entries into the Vapor Containment. The best estimate water levels were then plotted against times gleaned from Vapor Containment entry logs, operator logs and eyewitness accounts of the activities of the water level observing individuals. The resulting plot supports the licensee's estimate of maximum potential Reactor Vessel submergence and shows only one peak without level cycling.

g. Unresolved Items

At the completion of the onsite investigation, the licensee had not resolved the discrepancies between water level observations and volume calculations. Recent survey results strongly suggest that additional level indication should have indicated the collecting water level was about to flow into the Reactor Vessel Pit. Since no one reportedly observed this indication, the operability of the level detector, or the path river water utilized to enter the Reactor Vessel Pit, remains in question. To resolve these matters, the licensee has committed to providing NRC the following reports by 12/22/80.

(1) Reactor Vessel Pit Water Transport Path Report

-- explaining how water entered the reactor vessel pit without indication of this condition.

This item (50-247/80-19-31) is unresolved.

(2) Vapor Containment Survey Evaluation Report

-- providing surveyor results of floor sump and equipment elevations;

-- listing equipment and surfaces wetted during flooding event;

-- listing equipment potentially floodable had the condition not been accidentally detected;

-- discussing the impact of the actual wetting and planned corrective actions;

-- discussing the potential impact of the flooding had it continued; and

-- discussing the impact on the equipment and surfaces wetted of the residual levels of contaminants following planned corrective action completion.

This item (50-247/80-19-32) is unresolved.

(3) Recirculation Sump Activity Level Evaluation Report

-- providing an explanation, including the most probable source, for the observed activity of the recirculation sump water, following the flooding event.

This item (50-247/80-19-33) is unresolved.

13. Previous History of Containment Flooding

a. General

The inspector reviewed AEC, NRC and licensee documents of previously reported Containment flooding events, that lead to water flow into the Reactor Cavity Pit.

The review was conducted to identify events which had the potential for wetting the Reactor Vessel and to gather information relative to the events.

b. References:

-- Event 1

(1) WEDCO Containment Integrated Leak Rate Report

(2) Memorandum F. Noon to W. Monti, 1PP-80-556, dated November 14 1980

-- Event 2

(1) Consolidated Edison Co Report to AEC, dated 11/30/73

(2) Notification of Occurrence, dated 11/14/73

(3) IE Report 50-247/73-20

(4) Report to AEC, dated 1/14/74

(5) Memorandum J. Makepeace to J. O'Toole, dated 11/19/73

-- Event 3

(1) Reportable Occurrence Report 77-2-14

(2) IE Report 50-247/77-24

(3) Memorandum J. Dutch to J. Makepeace, dated 8/12/77

(4) Senior Watch Supervisor Log Excerpts, 7/1/77 to 7/5/77

c. Event 1 - March 7, 1971

On March 4, 1971, the Vapor Containment was subjected to a preoperational "Containment Integrated Leak Rate Test", which required the internal pressurization of the containment structure to a pressure of 47 psig.

Three days into the test, it was determined by the licensee's test coordinator, that liquid was collecting in the containment structure. Subsequent investigation found that pressurized temporary Service Water piping to a Fan Motor Cooler had failed.

Service Water (river water) was found on the Vapor Containment Floor, 4-6 inches, and in the Reactor Vessel Pit to a depth of approximately 13 feet. Based on a Reactor Vessel Pit Floor elevation of 18 feet, the additional flooding depth estimate of 13 feet, and a Reactor Vessel Lower Head bottom elevation of 34 feet, the Vessel should not have wetted (18 + 13 < 34).

During the period of potential Reactor Vessel wetting, the Vessel was at ambient temperature and had not yet been fueled.

d. Event 2 - November 13, 1973

On November 13, 1973, with the Reactor at 7 percent power and 547°F, a crack developed in an 18 inch feedwater line to No. 22 Steam Generator inside the Containment. Condensate (demineralized water) collected on the Vapor Containment Floor and in the Reactor Vessel Pit; the latter, to a measured depth of 56 inches. The Incore Instrument Conduits were subsequently cleaned. The Reactor Vessel Lower Head was not contacted by cold water during this event.

e. Event 3 - July 2, 1977

On July 2, 1977, with the Reactor at 2 percent power and 547°F, Control Room alarms and instrumentation indicated a failure of the No. 23 Reactor Coolant Pump seal package. Failure of the seal package enabled Reactor Primary Coolant to flow into the Vapor Containment and Reactor Vessel Pit. The licensee's report to NRC indicates the total loss of coolant to the Containment to be approximately 90,000 gallons. No documentation or report of observed water levels in the Reactor Vessel Pit following the event have been identified. Recent licensee calculations of the volume of water required to collect in the Vapor Containment to just touch the bottom of the Reactor Vessel Lower Head (94,000 to 97,000 gallons), would indicate that the spilled volume of hot demineralized water was probably not sufficient to touch the Reactor Vessel.

f. Conclusion

Of the three events identified as having potential for Reactor Vessel wetting, only the November 13, 1973, Feedwater Line Crack event can be ruled out with hard evidence as not wetting the Reactor Vessel.

The March 7, 1971, Service Water flooding event estimate of Reactor Vessel Pit flooding depth is poorly supported by documentation, and approaches contact of the Vessel within 3 feet. Based on the temperature of the Reactor Vessel at the time of the event, the material of Reactor Vessel construction and the characteristics of the Reactor Vessel painted surface. no problem with the Reactor Vessel would develop from this event had wetting occurred.

The July 2, 1977, Pump Seal Failure flooding event estimate of flooding volume closely approaches the required volume to contact the Reactor Vessel. Based on the initial 547°F temperature of the flooding water and the fact that the water was dimineralized, no excessive Reactor Vessel stress or corrosion problems are predicted.

14. Reactor Vessel Integrity Following Partial Immersion

a. General

As previously described, flooding of the Reactor Vessel (RV) Pit would cause partial immersion of the RV in water. Chloride ion swipe tests, described elsewhere in this report, and observations of Reactor Vessel Pit water level indicate that about 9 feet of the RV was immerse in River Water. This immersion produced thermal gradients that increas Reactor Vessel outside diameter surface tensile stresses.

Analyses of the effects of the unusual thermal gradients were made by the licensee, Westinghouse Electric Corp, and Nuclear Energy Services, Inc.

It was reported by Westinghouse that the efficiency of the mirror insulation is sufficient to maintain a condition of essentially no temperature drop accross the wall of the Reactor Vessel, during normal operation. Immersion would produce a thermal gradient that would add to operating pressurization stresses.

b. Stress Analysis

Analyses by Westinghouse indicated that immersion to the depth reported would result in three areas of concern. These are increased stresses in the lower head to cylindrical section transition, increased stresses at the locations of the lower head instrumentation nozzle penetrations, and permanent distortion of the tongue and groove joint into which the core barrel fits. In 1973, immersion stress and fracture toughness calculations were made (by W. H. Bamford, "Fracture Analyses - External Thermal Shock") assuming a deeper immersion in 130°F water and considering the calculated loss of toughness (from irradiation) at the end-of-design-life. These calculations indicated that a critical flaw would have to be approximately [illegible]% of the wall thickness.

The current Westinghouse fatique usage calculations, dated November 4, 1980 assumes 100°F water in contact with the RV. The ambient river water temperature at the time of the incident was approximately 65°F. The water from the relatively slow leaks had to flow over and remain in contact with 112-120°F structural material. The water temperature would rise asymptotically to the containment temperature. The Westinghouse fatique usage calculations did not elevate the Reactor Vessel outer wall temperature above that of the 100°F water. (A realistic boiling situation would only cool the RV outer wall to approximately 200-220°F, due to boiling film coefficients.) Finite element methods were used to determine temperature distributions, thermal stresses, pressure stresses and associated displacements. The stresses were categorized per NB-3223. Computer program WECEVAL (3) was used to linearize the stress distributions and determine the maximum range of primary and secondary stress intensities.

The calculations were made for 5 water level positions and the stress intensities were compared to ASME critiera.

The Westinghouse calculations show a maximum fatique usage factor per immersion of 0.0062 in the lower head/shell transition (a factor of 1.00 is required for calculated fatique failure). The nozzle penetration area fatigue usage factor per immersion is lower. The Westinghouse calculations show the displacement or rotation of the tongue and groove core barrel support to be less than the allowable tolerance.

A Westinghouse fracture analysis was made for the outside diameter surface temperature change, from normal operating wall temperatures to immersion temperatures, for transients from 50 seconds to 1500 seconds. Stress intensity factors (KI) were calculated in accordance with Appendix A of Section XI, Division 1 of the ASME Boiler and Pressure Vessel Code. The assumed surface flaw was a semi-elliptical surface flaw with a length to diameter ratio of 6, with longitudinal (worst case) orientation. The calculations used a conservative worst case bulk water temperature of 100°F and a heat transfer coefficient of 2000 BTU/hr-ft^2-°F, to determine the temperature of the outer wall. The analysis results in a critical flaw size of 1.05 inches for the bottom head and 1.68 inches for the lower shell.

Westinghouse also performed fracture analysis for the Incore Instrumentation tube penetration region. The analysis utilized a 100°F temperature for the outer wall of the vessel. The weld joint for the penetration is on the inside diameter of the vessel, which on the worst case is at 455°F, which keeps the metal (RV Steel Head) at the upper shelf of the fracture toughness curve. The maximum calculated stress intensity factor is an order of magnitude less than allowable. The calculation indicates there is no possibility for crack propagation associated with the nozzle penetration. This conclusion is in accordance with ASME Section XI, Appendix A analysis methods.

The analysis conducted by Nuclear Energy Services, Inc. was entitled "Thermal Transient Safety Evaluation of the Indian Point 2 Reactor Pressure Vessel Bottom Head During Containment Building Flooding". The NES evaluation utilized the LION4 heat transfer computer code to calculate the thermal response of the RV lower head to immersion in water. This analysis permitted lowering of the outside diameter of the RV to 212°F. A 10 GPM leak rate was postulated to provide the rate at which the RV was submerged. The ANSYS finite-element computer code was utilized for stress analysis. The primary and secondary stresses from pressure loading are within requirements of NB-3221.2 and NB-3221.3. The maximum secondary stresses resulting from axial and radial thermal gradients are within the requirements of NB-3213.13(a The calculated equivalent fatique usage factor per immersion is 0.0006 per cycle of immersion.

A review of the aforementioned analysis by the NRC inspector indicates that the immersion of the RV did not consitute a significant structural transient and had negligible effect on the life of vessel.

c. Unresolved Items

Based on NRC concerns expressed to the licensee for the acceptability of the assumptions used in calculating Reactor Vessel stresses and in defending his position that the Reactor Vessel had not been damaged, the licensee has committed to provide the following reports by 12/22/80:

Incore Instrument Stub Tube to Reactor Vessel Weld Failure Consequence Report

-- providing the results of flow rate calculations from an incore instrument thimble hole in the reactor vessel, should the tube to vessel weld experience a 360° failure;

-- assuming conditions with and without stub tube ejection.

This item (50-247/80-19-34) is unresolved.

Reactor Vessel Stress Analysis Report

-- assuming submergence in 60°F service water while at full power;

-- providing rational for continued operations.

This item (50-247/80-19-35) is unresolved.

15. Containment Paint and Insulation

The containment floor and wall liner are covered with a protective paint coating, over their entire surface. The wall liner is additionally protectec by insulation on its inside surface. This insulation is then covered with a metal canning, which is caulked between the wall sections and where the floor meets the wall. During various containment tours, the inspectors noted that the paint was damaged and peeling in many areas and that the caulking used for the metal canning was cracked and peeling, also. The licensee stated that both would be restored to their origional condition.

This item is unresolved and is designated as Item No. (50-147/80-19-36).

16. Mirror Insulation

a. Discussion

The NRC Inspector reviewed the insulation drawings with a representative of Diamond Specialty Company (B&W). The drawings reviewed were as follows:

MIC-369-001C
-J03C
-023C
-026C
-027C

The drawings indicated reflective metallic materials versus bulk insulation were utilized. The insulation consisted of panels, fabricated as an American Iron and Steel Institute 304 jacket with a 3003 Aluminum multi-layered mirror lining, and stainless steel wool insulation, between the instrumentation nozzles and mirror insulation jackets. The insulation was ordered from Diamond Specialty, as a Westinghouse Subcontract, and installed to WAPD 54-F70611B.

Since expansion and escape of the air trapped under the insulation must be allowed in the design of the insulation system, the insulation is not water tight; and therefore, must be assumed to have allowed river water on the inside diameter of the stainless steel jacket. Exposure of the mirrored surface to an active corrodant might have adverse effects on the insulation capabilities. Visual inspection of the insulation by the NRC inspector did not reveal any indication of damage to the insulation by the immersion in diluted river water.

b. Unresolved Items

The licensee has committed to provide to the NRC by December 22, 1980, a report which will:

-- describe the test procedures and objectives of a program to demonstrate that the mirror insulation will perform in accordance with specifications.

-- justify that the Reactor Vessel can safely operate in accordance with technical specifications with degraded mirror insulation.

This item is considered unresolved and is designated Item No. (50-247/80-19-37).

17. Steam Generator Blowdown Line Leaks and Supports

a. References: (1) Quality Control Inspection Reports (Q.C.I.R.s) 80-2-42, 42A, 42B

(2) MWR - 2937 - Steam Generator No. ?1

(3) Dwg 9321-F-2558-3

(4) MWR 1715 and 1719

(5) I.P. Station Maintenance Procedure - Removal of No. 21 Steam Generator Shell Drain Line (SNSC Approved 6/9/80)

(6) Safety Evaluations, 10 CFR 50.59

b. Latest Leak

On October 18, 1980, during a Vapor Containment entry, an operator identified a leak on the blowdown piping from No. 21 Steam Generator.

The ? inch line had developed a leak at an inboard 45^{o} weld which caused a visible plume inside the Missile Shield. The leak was temporarily repaired with an overlay of weld material. An operations pressure test was conducted at the conclusion of the repairs. During subsequent Quality Control Inspections of the repairs, the licensee identified on Q.C.I.R.s, three missing pipe hangers. Discussion with corporate field Quality Assurance Engineers indicated that the three hangers, identified by the Q.C.I.R.s, were to be replaced.

c. Previous Problems

On June 7, 1980, a shell drain line from No. 21 Steam Generator failed at the Steam Generator/pipe interface. This line shares a common discharge header with the No. 21 Steam Generator Blowdown Line, which developed a leak on 10/18/80. Repairs of the drain line involved welding a new pipe stub on the Steam Generator, removing an isolation valve, and plugging the two open pipes, thus eliminating the shell drain. The licensee attributed the line failure to water hammer from the operator of the solenoid operated isolation valve. The licensee had further identified one hanger and one snubber which had failed. The NRC Resident Inspector made a tour of the area on 6/9/80, and verified the licensee documented observation.

d. Unresolved Items

(1) The inspector requested the licensee to perform the following items to assure the blowdown piping system is properly supported:

(a) Review licensee's response to Inspection and Enforcement Bulletin 79-14 and the results of the licensee's surveys as to the ability of the present hangers to seismically support blowdown system piping;

(b) Verify by walking the lines, that the present hangers on the blowdown piping are located in accordance with as-built plans;

(c) Identify and resolve discrepancies in accordance with Quality Assurance Procedures;

(d) Describe analysis performed that justified elimination of a number of hangers on the blowdown system; and,

(e) Describe hydraulic shock effects on the blowdown piping resulting from opening and closing the solenoid operated isolation valves.

This item (50-247/80-19-38) is unresolved pending the completion of the licensees investigation and review of resulting documentation by the NRC.

(2) Based on NRC concerns expressed to the licensee at a public meeting on November 5, 1980, the licensee has committed to provide the NRC the following report by December 22, 1980.

Steam Generator Blowdown Line Failure Analysis Report

-- providing a description of tests and inspections performed to identify the cause of failures.

-- detailing the results of the analysis of failures.

-- explaining why the proposed modified or repaired system is immune to the identified failure mechanisms or why these failure mechanisms are now tolerable.

This item (50-247/80-19-39) is unresolved.

18. Corrosive Effects of Immersion in River Water

a. General

The leakage of the Fan Cooler Units and Steam Generator Blowdown Line into the recirculation sump, Vapor Containment sump and finally the Reactor Vessel Pit, caused partial immersion of the Reactor Vessel, immersion of the Reactor Vessel Incore Instrumentation nozzles and conduits, immersion of a portion of the Residual Heat Removal piping, and immersion of a portion of the Reactor Vessel Mirror Insulation.

The materials exposed to the diluted river water corrodant were the SA302, Grade B (Manganese-molybdenum low alloy steel) weld fabricated Lower Reactor Vessel Head, Alloy 600 (Nickel-chromium-iron) Incore Instrumentation nozzles with a 316 stainless steel nozzle safe-end, 316 stainless steel Incore Instrumentation Conduit and Conduit couplings, and stainless steel jacketed aluminum Reactor Vessel Mirror Insulation.

The corrosive effect of exposure of metallic parts to diluted Hudson River water was studied by the NRC Corrosion and Metallurgy Specialist and determined to be a function of the following:

1. Alloy composition
2. State of surface stresses during exposure
3. Corrodant and concentrating mechanisms
4. Metal temperature
5. Time of exposure

b. Material of Construction

The NRC Specialist reviewed the Reactor Vessel fabrication sequence obtained through Westinghouse Corporation. The Reactor Vessel was fabricated by submerged arc welding. The lower head consists of a lower dome and orange peel (torus) segments. The contoured sections are hot formed above the lower critical temperature, then quenched and tempererd to produce the desired toughness and mechanical properties. The bottom dome is surfaced (weld clad) on the inner diameter with austenitic stainless steel, then given a subcritical interstage post weld heat treatment (P.W.H.T.). The orange peel sections are joined together by submerged arc welding, given a subcritical interstage P.W.H.T., then surfaced on the inner diameter (weld clad) with austenitic stainless steel, and then given another P.W.H.T. The bottom dome is then joined to the orange peel sections and the joint surfaced (weld clad) with austenitic stainless steel, and then given an intersta P.W.H.T. The holes and weld joint geometries are then machined for the Incore Instrumentation nozzles. The exposed steel on the nozzle weld joint geometry is manually weld surfaced (clad) with a Ni-Cr-Fe (Inconel type) filler metal, as is a pad approximately 3 1/2" in diameter, by approximately 3/8 inch thick deposited around the holes on the outside diameter of the head. Following this welding is another interstage P.W.H.T. The Reactor Vessel Lower Head is then joined to the lower Vessel assembly by submerged arc welding, the weld joint back surfaced (clad), and given another interstage P.W.H.T. Following joining of the lower Vessel assembly to the upper Vessel assembly (closure seam), the entire vessel is then given a complete P.W.H.T.

The Ni-Cr-Fe Alloy 600 nozzles are then inserted in the Incore Instrument penetration holes in the Reactor Vessel Lower Head. The diametral clearance of the nozzles and penetration holes is 0.004" maximum. The nozzles are then welded into the Head using Ni-Cr-Fe (Inconel type) filler metal. The weld metal is deposited on the surfaced (clad) weld joint geometry, thus eliminating a weld HAZ on the RV head.

The complete sequence of intermediate and final P.W.H.T. of the Reactor Vessel pressure boundary welds, should render the lower Head and porton of the lower Vessel Assembly, which was exposed to the corrodant, essentially free of weld induced residual and other fabricating stresses Following hydrostatic testing of Reactor Vessel and magnetic particle testing (MT) of the entire outside diameter exposed surface, the vessel is painted with a 2-4 mil single coat of Placite 888 (an aluminum rich silicone base high temperature paint). The painting system meets the requirements of Westinghouse WCAP 7153. The painting sequence accounts for the observation of paint droplets on the Instrumentation nozzles.

The austenitic stainless steel weldments (Incore Instrument Conduit to Nozzle safe end socket fillet welds and Conduit to Conduit socket fillet coupling welds) and the austenitic stainless steel safe end to Nozzle weldments did not require or receive a P.W.H.T. These weldments could retain yield strength level residual welding stresses. The weld area including the weld HAZ must be assumed to have surface tensile stresses.

c. Material Susceptability to Corrosion

The corrodant is Hudson River Service water, diluted with steam from a Steam Generator Blowdown Line leak. The maximum concentration of Chlorides was believed to be approximately 3400 ppm, NaCl, as analyzed by the licensee's Chemistry Lab from water taken from the Reactor Vessel Pit. It is a reasonable assumption that this water was in contact with the heated surfaces of the Reactor Vessel, radiation heated

Reactor Vessel Mirror Insulation and conduction heated Incore Instrument Nozzles. The heated surfaces could provide a concentrating mechanism for the chlorides. The unheated surfaces would not provide a concentrating mechanism for the chlorides.

The metal temperature of the heated parts exposed to the corrodant may be assumed to be approximately that of the boiling point of water. The time of exposure from all existing data appears to be less than 51 hours.

The Reactor Vessel Head material and Ni-Cr-Fe Alloy 600 Nozzle material are known to be resistant to stress corrosion cracking in the presence of chlorides. The austenitic stainless steel weld area of the heated Ni-Cr-Fe Nozzle to 316 safe end and safe end to conduit welds are less resistant to stress corrosion cracking, as they contain the necessary prerequisites of a susceptible material, possible surface residual tensile stresses, a temperature above 150°F and the presence of chlorides. These areas are considered to be the most susceptible to corrosive attack during the immersion.

d. Recommendations and Results

The NRC Corrosion and Metallurgy Specialist indicated that all areas which could have been adversely affected by the corrodant, should be subjected to non-destructive examination to detect the presence of incipient cracking. The licensee conducted magnetic particle testing of all weld seams on the Reactor Vessel Lower Head and dye penetrant testing of Incore Instrument Nozzle safe end welds, Nozzle to Conduit socket fillet welds, conduit coupling socket fillet welds, and the entire length of Conduit immersed in the corrodant. No indications were reported by the licensee.

The NRC conducted a third party verification inspection of the Reactor Vessel welds and a statistical inspection of the austenitic stainless steel welds. The third party inspection also reported no indications.

The licensee and third party NDE results indicate that the immersion of the vessel in the corrodant resulted in no corrosion damage to the exposed parts.

19. Chloride Contamination Survey

a. Chloride Swipe Test

The swipe test for chlorides is routinely used to determine levels on "Chloride free" and "chloride contaminated" surfaces. A standard chloride level for a "chloride free" surface is <0.08 mg/dm^2. The test consists of taking a clean (gauze square) swathe cloth and wiping an area approximately 10 cm x 10 cm (1 dm^2), boiling the swathe to transfer the retained chlorides to solution, then acidifying and titrating with Hg $(NO_3)_2$ to determine chlorides (ASTM:D512 Chloride Technique). Due to slight technique variations in the exact determination of the area and variable applied pressure used to achieve the wiping of the surface, the test cannot be considered to produce absolute quantitative results.

In order to verify the test, the licensee conducted a referee test utilizing a Dionex Model 14 ion chromatograph. The licensee indicated that the ion chromatography verified that their swipe test procedure accurately reported titrated chlorides and that on the specific swipe test, verified that the chlorides came from a water sample qualitatively and semi-quantitatively the same as the river water sample obtained on 10/22/80. The ion chromatography procedure followed for chloride analysis is not a standard ASTM procedure, but is currently being reviewed by committee D19 as a proposed analysis method. The referee test is basically a verification that the Hg $(NO_3)_2$ titration technique for the swipe test is properly reporting Chloride Ion concentration and characterizing the solutions analyzed as river water.

b. NRC Observations

The NRC inspector witnessed a complete laboratory "boildown" and a complete "dip" swipe test with a referee blank sample. The dip test was accomplished by wetting the inside surface of a stainless steel tank for the ultrasonic cleaner with River water, allowing it to dry, and wiping an approximately 100 cm^2 area with a swathe. The "boildown" test consisted of taking 50 ml of the 1 meter deep weekly composite 10/22/80 River water sample and evaporating to complete dryness in a 500 ml beaker. The surface area wetted with 50 ml of water in a 500 ml beaker was measured and estimated to be 113 cm^2. Upon completion of evaporation and cooling, the beaker showed a relatively heavy layer of dried salts. The contaminated surface of the beaker (approximately 113 cm^2) was wiped with a swathe cloth using the standard swipe test procedure. The results were 113 mg by titration methods. A licensee calculation of the chlorides expected, based on 4600 ppm NaCl in the River water, was 139 mg (in 50 ml).

c. Licensee Findings

The initial series of swipe tests were conducted from 10/20/80 to 10/24/80. The swipe test results for chlorides conducted on the ambient temperature stainless steel conduit lines varied between 0.1 and 1.0 mg/dm^2, which is on the order of that determined by the laboratory (ultrasonic cleaner tank) ambient temperature dip test which was 0.2 gm/dm^2. The swipe tests conducted on the Reactor Vessel Head yielded results which varied from 20 to 80 mg/dm^2, with one probably bad result of 117. These values are indicative of boildown concentration mechanisms and are similar to that obtained in the laboratory 50 ml boildown tests. The results of swipe tests taken on the outside diameter of the mirror insulation are greater than those for the unheated conduit (between 1.2 and 1.7 mg/dm^2) but less than the chlorid obtained from the hotter surfaces on the Reactor Vessel Head.

A second series of swipe tests were run on the Reactor Vessel from 10/29/80 to 11/3/80. The 10/29/80 swipe tests were run at 4 radial locations on the Reactor Vessel Head, essentially every foot of elevation, from the bottom of the Reactor Vessel Head to an elevation of 7 feet. On 11/3/80, an additional series of Reactor Vessel Swipe tests were run from an elevation of 7 feet to 10 feet, above the bottom elevation of the Reactor Vessel Lower Head. The swipe test results from the one foot to 7 foot elevation vary from 10.2 - 72 mg/dm^2.

The 7 foot to 10 foot swipe test series statistically show lower values (6.0 - 14.5 mg/dm^2). The swipes at one radial location indicate the most probable high water level with the following values:

Est. Relative Bldg. El.	Height Above RV Bottom	Cl^- (Mg/dm^2)
	7'10"	14.5
42'	8'0"	11.5
	8'4"	12.5
	8'8"	0.36
43'	9'0"	0.68
	9'6"	0.36
44'	10'0"	0.23

The water level indicated by these chloride swipes was most probably between the 8 foot 4 inches and 8 foot 8 inches height on the Reactor Vessel, which roughly corresponds to 42 foot 4 inches to 42 foot 9 inches, in building elevation. The values below the 8 foot 4 inch level on the Reactor Vessel represent concentration caused by the heated surface. The values above the 8 foot 4 inch level represent chloride carryover from the boiling regime.

d. Unresolved Item

Based on NRC concerns expressed to the licensee at a public meeting on November 5, 1980, the licensee has committed to provide the following report to NRC by December 22, 1980.

Reactor Vessel Paint Chloride Retention Report

-- describing the results of tests, inspections or analysis that establish the probable Chloride residue retained by the reactor vessel paint.

-- discussing the impact of the residue on continued operations.

This item (50-247/80-19-40) is unresolved.

20. Non-Destructive Examination of Reactor Vessel Lower Head, Incore Instrumentation Nozzles and Conduit, and Residual Heat Removal Piping

a. NRC Observations

The Reactor Vessel (RV) Lower Head was visually examined by the NRC Corrosion and Metallurgy Specialist shortly after removal of the lower head mirror insulation. Examination was made with the unaided eye with marginal lighting and a flashlight. The RV Lower Head is painted with a heavily layered beige colored paint. It appears that the paint was applied after installation of the instrument penetration nozzles, as a considerable amount of paint drops were observed on the nozzles. No evidence of red rust ($Fe(OH)_3$) was noted, even in areas where it appears there is little or no beige paint. No evidence of heavy salt encrustation was noted on the head; however, there appeared to be a translucent haze on the painted head.

Portions of the stainless steel wool type insulation continued to adhere to the nozzle/head intersections. This material did appear to have the color of red rust.

No evidence of localized or general corrosion attack on the head, nozzles or conduit was noted. No evidence of any linear cracklike indications were noted in suspected areas of high surface tension stresses, i.e., weld HAZ.

No pigmented corrosion products were noted on the Ni-Cr-Fe Alloy 600, nozzle, nozzle to safe weld, 316 safe end, safe end to conduit socket fillet weld, 316 conduit, or conduit to coupling welds. No evidence of heavy or light salt encrustations were observed on the aforementioned parts.

b. Licensee Examinations - Incore Instrument Nozzles

The licensee conducted a series of dye penetrant (PT) examinations, of the non-ferrous reactor welded joints exposed to the diluted river water. These joints consisted of the Ni-Cr-Fe Alloy 600 instrumentation nozzle to austenitic stainless steel safe end welds, nozzle safe end to austenitic stainless steel conduit socket fillet welds, and conduit coupling welds. The first results were reported in QCIR 80-2-44, dated 10/24/80. Due to the residual heat in the RV, a high temperature (125-150°F) PT technique was required for the nozzles. In addition to the 21 nozzle safe end and socket welds examined, 32 20-25" long sections of conduit not containing welds were examined. No relevant indications were noted.

On 10/25/80, the licensee attempted to conduct PT examinations of the complete nozzle extension. This PT examination utilized a PT cleaner as a pre-cleaner, but resulted in a large number of non-relevant indications caused by the paint drops remaining on the nozzles. Licensee representatives indicated that mechanical cleaning would be necessary if these areas of the nozzles were to be given a PT examination. The NRC inspector concurred that minor cleanup with emery paper should be utilized, where required. The results of the PT over the paint drops were disregarded due to the prevelance of non-relevant indications; however no crack like indications were noted. The NRC inspector witnessed a small sample of the licensee's dye penetrant (PT) examinations and reviewed results for a complete (10/25/80) reexamination of all nozzle to safe end welds and safe end to conduit socket fillet welds. No relevant indications were reported.

c. Licensee Examination - Reactor Vessel

On 10/29/80 and 11/1/80, the licensee conducted a 100 percent magnetic particle (MT) inspection examination of the dome to torus, torus longitudinal, torus to lower shell and 16 inches of the two lower shell longitudinal welds. The NRC inspector reviewed the procedure performed on unpainted and painted test assemblies, including review of the photographs showing reproducible powder indications. The MT examinations showed no indications.

d. Licensee Examination - Incore Instrument Conduits

The licensee also conducted a 100 percent PT examination of the portion of the 58 conduit lines exposed to the flooding water. No indications were reported.

e. Licensee Examination - Residual Heat Removal (RHR) Piping

A portion of the RHR stainless steel piping which extends to the Vapor Containment Sump was exposed to ambient temperature diluted river water. The RHR piping was hydro-statically tested at 100 psig for 60 minutes and visually examined by the licensee for leaks on the outside diameter of the pipe at the weld joints. No leaks were reported.

The licensee radiographically examined weld numbers 57-3 to 57-6. No indication of chloride ion cracking was identified. Engineering disposition of identified welding and manufacturing defects indicated these defects were not related to the exposure to river water and were considered to be acceptable.

f. Licensee Examination - Procedures & Personnel

The licensee procedures and qualifications of NDE personnel were reviewed by the NRC inspector. No problems were identified.

21. Independent Nondestructive Examination of the Indian Point Unit 2 Reactor Vessel Lower Head Welds, Stub Tube Welds and Conduit Welds

a. General

Following the determination that the Reactor Vessel Lower Head and Incore Instrument Conduits were submerged in Service Water, while at normal operating temperature, the licensee performed nondestructive examinations of the Reactor Vessel Lower Head welds, Stub Tube welds and Incore Instrument Conduits.

The NRC contracted Parameter Incorporated of Milwaukee, Wisconsin to provide an independent nondestructive examination of the above mentioned welds and conduits to verify the licensee's examination results.

b. Work Scope

The work scope was as follows:

(1) Provide a technical evaluation of the suitability of performing a magnetic particle examination of the reactor vessel lower head, without removal of the protective coating.

(2) Perform a procedure qualification to demonstrate that the magnetic particle examination methodology to be used is capable of detecting flaws in the licensee's coated calibration standard.

(3) Supply the necessary qualified (SNT-TC-1A) personnel and equipment, perform magnetic particle inspections using the AC yoke method of the following IP-2 reactor vessel welds:

(a) Circumferential Lower Head to Shell weld.

(b) Lower Head meridional welds (orange peel).

(c) Lower Head circumferential weld (dollar piece).

(d) One foot of the longitudinal Shell welds, intersecting the circumferential Shell to Lower Head weld.

(4) Supply the necessary qualified (SNT-TC-1A) personnel and equipment, perform liquid penetrant inspection of the following:

(a) 25 percent of the instrument nozzle to safe-end and safe-end to instrument socket welds. Include in the sample those nozzles which are observed to have longitudinal marks.

(b) 10 percent of the conduit welds which could have been exposed to the leaking service water.

c. Personnel

The above work was done by six Peabody Testing Services personnel under the direction of an NRC N.D.E. Specialist.

The examination personnel were qualified and certified as follows:

Magnetic Particle Examination

-- Two Level III individuals

-- Four Level II individuals

Liquid Penetrant Examination

-- Two Level III individuals

-- Two Level II individuals

-- One Level I individual

d. Technique

Magnetic particle examinations were done using Magnaflux Corporation model Y-6 AC yokes, serial number HAR-30 and HAR-34. The welds were examined using the continuous method in accordance with Peabody Testing Magnetic Particle Examination Procedure Number 21.A.3-4, Revision 1. The aforementioned examinations were done after the flaws in the licensee's coated calibration standard were satisfactorily detected.

The liquid penetrant examinations were done using visible dye, solvent removable penetrant materials, which were certified to contain permissible amounts of sulfur and halogens, as specified in the Peabody Liquid Penetrant Examination Procedure Number 23.A.1-4, Revision 1.

e. Results

No relevant indications were detected by either the magnetic particle or liquid penetrant method.

22. QA/QC Program

a. References

-- CI-240-1, Quality Assurance Program for Operating Nuclear Plants, Revisions dated August 15, 1977 and August 15, 1979.

-- FSAR Volume A, Attachment A-2, "Quality Assurance Program (ANSI N18.7 Format) revised June 1977"

-- SAO-113, Quality Control Reports and Stop Work Authority, Revisions 0 and 1.

b. Analysis of Indentified Failures

During review of the documents/procedures listed above and in other sections of this report, the inspectors noted that the manner in which the QA Program is implemented for failure analysis was not clearly described in established procedures. This concern was discussed with the licensee who committed to provide NRC by December 22, 1980, a Failure Analysis Program Description, which would:

-- provide a description of the program for analysis of equipment and component failures, as to cause.

-- explain how the program detects trends not obvious to the day to day observer.

-- explain how the program analyzes the potential impact of failures, had they gone undetected, to identify new safety issues.

-- explain how the program establishes corrective action priorities based on perceived risk.

-- identify the document which establishes the position responsible for the implementation of the program.

This item is unresolved pending review of the licensee's stated actions (50-247/80-19-41).

c. Corrective Action Program

The inspector reviewed Quality Control Inspection Reports (QCIRs) to verify that:

-- QCIRs documenting conditions adverse to quality were issued to a designee for corrective action.

-- QCIRs issued for corrective action were responded to promptly.

-- QA/QC followed up open/unresolved QCIRs, issued for corrective action, and verified corrective action.

-- Corresponding MWR subject matter supported the QCIR finding.

-- Accepted completed or proposed corrective action was adequate and timely.

The QCIRs and applicable Maintenance Request Forms (MWR) reviewed were:

-- 73-2-184, Containment Ventilation Cooling System - #23 Cooling Coil (MWR 1526).

-- 75-2-47, Service Water - #23 FCU (MWR 4161 and 4873).

-- 76-2-001, Service Water - #25 FCU (MWR 4455).

-- 76-2-17, SS Spool Piece in SW #23 Fan Motor Cooler Supply Line #496.

-- 76-2-146, Emergency Power - Diesel Generators

-- 77-2-39, SWS 2" Pipe - #24 EPI SEAL Repair (MWR 6246)

-- 77-2-52, Containment Penetration - Electric and Test Penetration EPI SEAL Repair (MWR 6017)

-- 77-2-69, Ventilation - #24 FCU Brazing of Leak (MWR 6511)

-- 77-2-70, Ventilation - #24 FCU EPI SEAL Repair (MWR 6511)

-- 77-2-83, Completed MWRs Not Transmitted from Construction to the Nuclear Power Generation

-- 77-2-89, SWN-Line #45 EPI SEAL Repair (MWR 6783)

-- 78-2-27, Containment Ventilation - FCU #23 EPI SEAL Repair (MWR 7242)

-- 78-2-62, SW-SWN #23 FCU

-- 78-2-91, SWN #24 Fan Cooler EPI SEAL Repair

-- 78-2-113, Pipe Penetration Elevation 51' West Pipe Supports Residue Buildup (MWRs 6991 and 0720)

-- 78-2-120, RHR Support ACH 67/SR-52-Line #9 (MWRs 7828 and 7960)

-- 78-2-124, FSB Ventilation Weld Repair (MWR 6928)

-- 79-2-14, Containment Air Lock Penetration Electric EPI SEAL Repair (MWR 6017)

-- 79-2-27, CVCS - Repair Seals #22 Charging Pump (MWR 0065)

-- 79-2-43, SW Pump (Hold Tag 72RI140)

-- 79-2-44, BFD Lines

-- 79-2-64, SW 10" Header - FCU #21 (MWR 0374)

-- 79-2-66, SW #25 Fan Cooling Unit (MWR 0427)

-- 79-2-74, SG #24 Seismic Restraint - Temporary Oil Reservoir (MWR 790497)

-- 79-2-75, SWN - #24 FCU MASTER BOND Repair (MWR 0444)

-- 79-2-77, SW Line #10C - FCU #24 EPI SEAL Repair (MWR 0835)

-- 79-2-82, Containment Pressure Relief - PCV 1191 (MWR 0953)

-- 80-2-01, Emergency Diesel Generators Nos. 21, 22, 23 Level Gages (MWR 8638)

-- 80-2-13, Containment Cooling and Vent - FCU #25 EPI SEAL Repair (MWR 1158)

-- 80-2-17, Aux BFD - 3/8" SS GNBF6 Whitey Valve (MWR 1067)

-- 80-2-18, Aux Feedwater System - #22 Aux BFP (MWR) 1067)

-- 80-2-19, CRDM Fans - Air Scoops (MWR 1162)

-- 80-2-23, BFD - Line #5

-- 80-2-25 and 25A, ESG - Bistable PC 429E (MWR 0126)

-- 80-2-28, Containment Cooling and Vent - #25 FCU EPI SEAL Repair

-- 80-2-29, Containment Cooling and Vent - #25 FCU EPI SEAL Repair (MWR 2057)

-- 80-2-33, Ventilation - Carbon Filters FSB

-- 80-2-39, Ventilation - #25 FCU Repair With Clamp and Gasket (MWR 2850)

-- 80-2-40, CRDM - Fans

-- 80-2-41, CVCS - SHT Lo Pressure (MWR 1759)

-- 80-2-42, Secondary Blowdown - SG #21 Line 46 (MWR 2937)

-- 80-2-43, MBFD - Valve FCV 437 (MWR 2933)

-- 80-2-46, SW - FCUs 21, 23, 25 EPI SEAL Repairs (MWRs 2940, 2935, 2944)

One item of noncompliance and an unresolved item are discussed below.

(1) 10 CFR 50, Appendix B, Criterion XVI requires that measures be established for prompt identification and correction of conditions adverse to quality. FSAR Volume A, Attachment A-2 also requires prompt correction to adverse conditions identified on a Quality Control Inspection Report (QCIR). SAO-113, Revision 0, requires that the response to a QCIR to be in writing and states this should normally be done within three working days.

Contrary to the above, the established measures (e.g., QCIR system) did not assure prompt correction of conditions in that the following conditions were identified by the inspector.

-- Eight QCIRs issued between April 2, 1979 and September 4, 1980 had not been responded to as of October 29, 1980.

-- Eight QCIRs had never been responded to, but were closed by various other followup actions initiated by the QA Engineer.

-- Four QCIRs, now closed, were not responded to for 18 days to over five months.

These examples constitute an item of noncompliance (50-247/80-19-42).

(2) The inspector noted and stated his concerns that licensee Procedure SAO-113 did not clearly define what period of time constitutes prompt response to a QCIR; the time frame within which the corrective action must be completed unless otherwise agreed to; the escalation of action for nonresponses or unacceptable proposed resolutions.

The inspector was provided with a copy of a licensee Audit Report 80-40-5A (a draft), which recently identified problems in the QCIR use area; and, drafts of CI-240-1, QA-AD-23 and SAO-113 which addressed the audit findings and the inspector's concerns. Pending review of the above issued procedures and other applicable licensee action with respect to the audit findings, this item is unresolved (50-247-80-19-43).

d. Maintenance Program

During the review of maintenance program administrative controls, the inspector noted that maintenance activities are controlled by a Maintenance Work Request (MWR). Work performed per an MWR is then done using only the MWR itself; an investigative checklist; a step list (more detailed and reviewed by QA); or an approved maintenance or modification procedure. Each succeeding method is more formalized, more detailed and provides more control and documentation of the maintenance activity. As a result of this review and the review of MWRs listed in subparagraph c. above and elsewhere in this report, the inspectors identified four unacceptable items as discussed in the following paragraphs.

(1) Fan Cooler Unit leaks have been repaired from 1973 to date using an epoxy sealant and categorizing the modification as maintenance. No evaluation was made until August, 1979, to determine that an unreviewed safety question was not involved using this method of repair. The engineering evaluation performed during August, 1979, did not consider all of the post-LOCA conditions of the specific mode in which the sealant was used. The plant was operated at power after each of such repairs from 1973 until October 17, 1980. The foregoing is contrary to: 10 CFR 50, Appendix B, Criterion II, which requires programatic control over such activities; FSAR Volume A, Attachment A-2, which commits to ANSI N18.7, which in turn requires that the maintenance program provide for maintaining of safety related systems to specified

quality levels and evaluation of material useage; and, 10 CFR 50.59(b) which requires that safety evaluations be performed for changes to the facility and those records retained.

The inspectors also identified that the Station Nuclear Safety Committee did not review, as required by TS 6.5.1.6, the modifications made to Service Water Piping and Cooling Coils, associated with the Fan Cooler Units, between 1973 and October 21, 1980. These modifications were designated "temporary repairs" and were made to leaking components, using epoxy type sealants and pipe clamps.

The above constitutes an item of noncompliance (50-247/80-19-44).

(2) Despite continued Fan Cooler Units leakage and many repairs of these leaks between 1973 and October, 1980, the licensee had not made any determination of the causes of the leakage problem or recorded such action; nor had the evaluation of the causes for such leakage, which had been initiated, ever been completed.

This is contrary to: 10 CFR 50, Appendix B, and Criterion II, which requires programatic control over such activities; and FSAR Volume A, Attachment A-2, which commits to ANSI N18.7-1976, which in turn requires that the causes of malfunctions (i.e., leaks) be promptly determined, evaluated and recorded.

This is an item of noncompliance (50-247/80-19-45).

(3) Technical Specification (TS) 6.8.1 commits to ANSI N18.7-1972, Paragraph 5.1.6.1 of which requires that maintenance and modifications that may affect the functioning of safety related systems be preplanned and performed in accordance with written procedures appropriate to the circumstances.

Contrary to this requirement, site administrative procedures were not established, implemented and maintained to provide guidance as to: (1) when written and approved procedures were required for maintenance activities; and, (2) when maintenance activities constitute a modification; both of which require review and concurrence by the Station Nuclear Safety Committee. The inspector was aware of a memorandum that discussed modifications, which had been issued (March 14, 1977) by the Director of Quality Assurance. The inspector noted that these instructions did not appear to have been implemented in that: (1) there were no corresponding site or maintenance department instructions; (2) past and present Maintenance Engineers were unaware of it; and, (3) if the instructions had been implemented, the epoxy repairs discussed elsewhere in this report would have been considered as modifications, which they (the epoxy repairs) were not.

This is an item of noncompliance for failure to establish and implement appropriate procedures (50-247/80-19-46).

23. Information Documents

The licensee has a set of manuals called System Descriptions. which provide both general and detailed information on each system in the plant. There are many copies of this set of manuals in the plant and they are used by many personnel, such as engineers and control room operators, for reference. During the investigation, the inspectors noted that many portions of these system descriptions are outdated and provide incorrect information. Some are as old as 1973. The inspectors also noted that the computer manual provided in the control room for operator reference was outdated and did not agree with current computer print outs. This item is unresolved and designated Item No. (50-247/80-19-47).

24. Unresolved Items

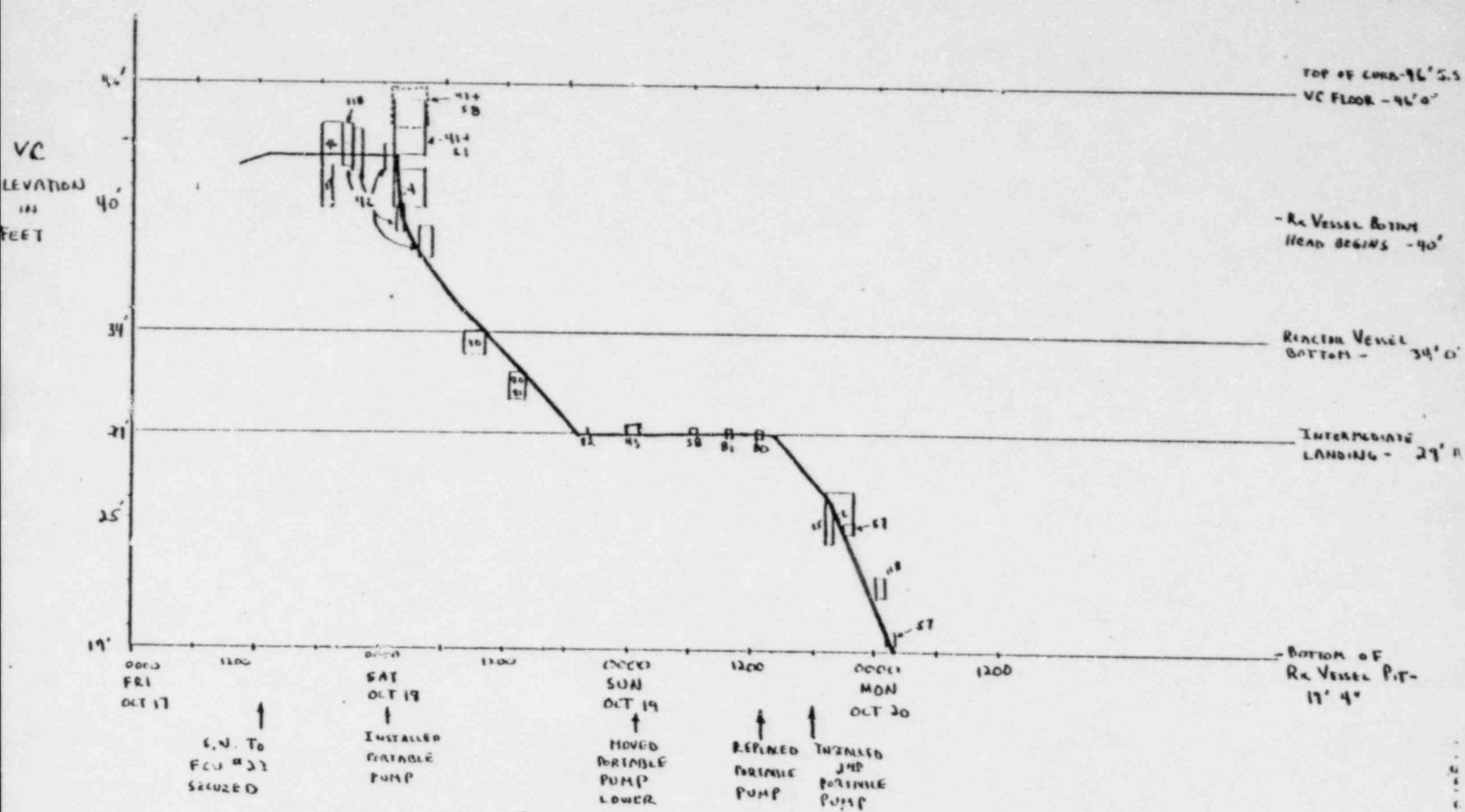
Unresolved items are items about which more information is required to ascertain whether they are acceptable items, items of noncompliance, or deviations. Unresolved items are discussed in Details pargraphs 5, 7-12, 14-17, 19, 22 and 23 of this investigation report.

25. Management Meetings

During the period of the investigation, licensee management was periodically notified of the preliminary findings by the NRC Investigation Team. A summary was also provided at the conclusion of the investigation.

LIST OF FIGURES

PLOT OF BEST ESTIMATE OF WATER LEVEL IN REACTOR VESSEL PIT VERSUS TIME, BASED ON ACTUAL WATER LEVEL OBSERVATIONS



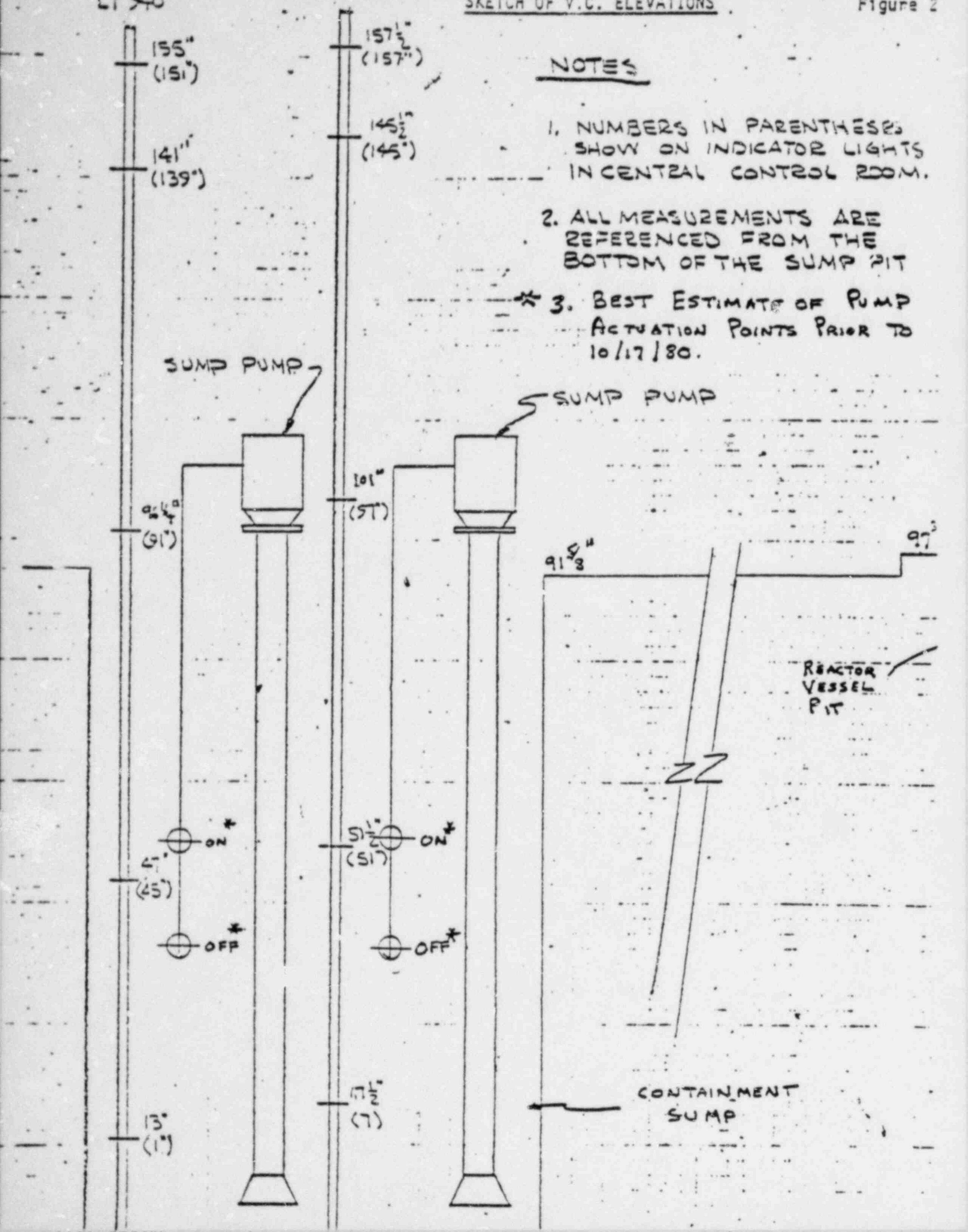
Note: The rectangles around individual observations represent the uncertainty associated with that observation.

SKETCH OF V.C. ELEVATIONS

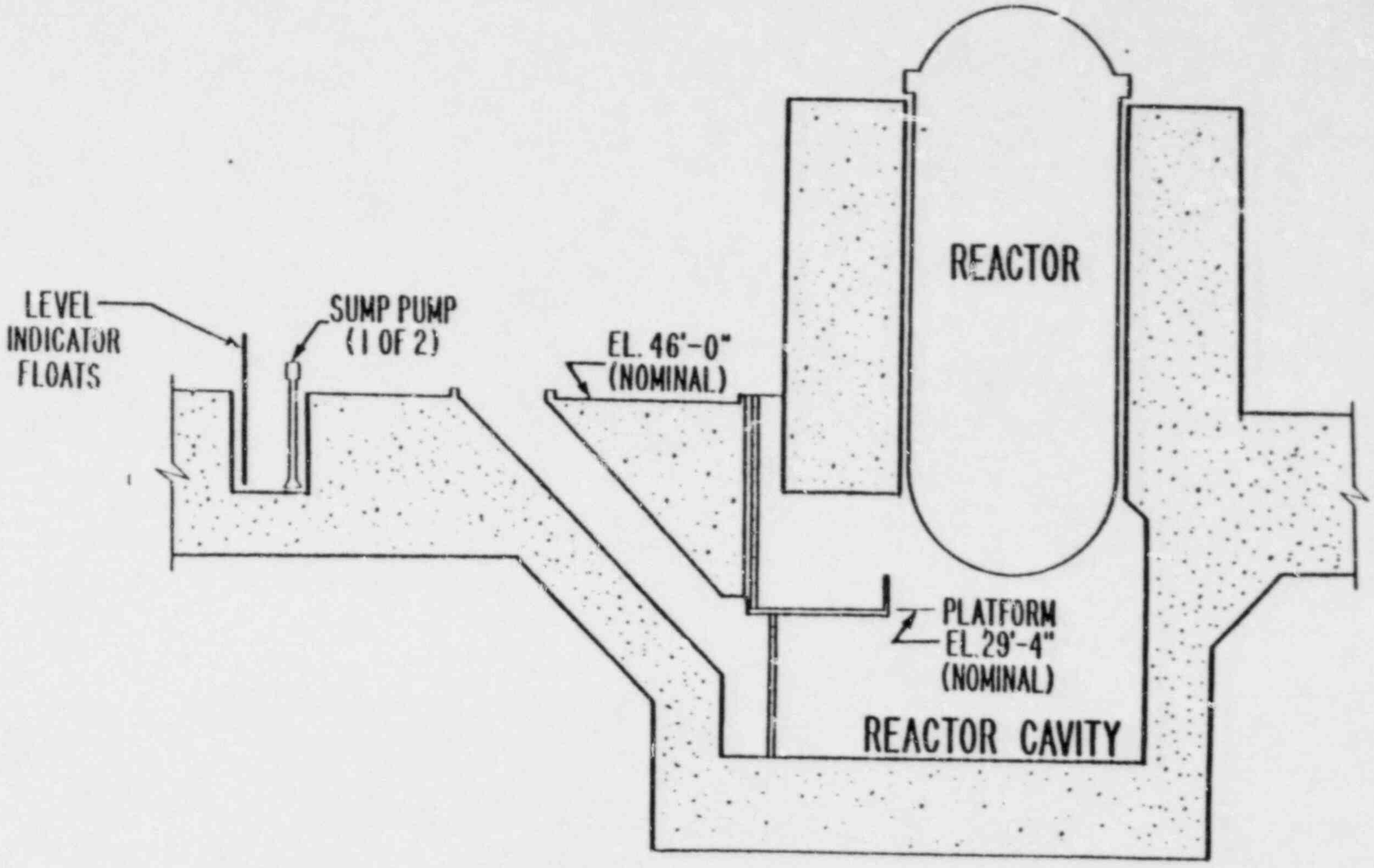
Figure 2

NOTES

1. NUMBERS IN PARENTHESES SHOW ON INDICATOR LIGHTS IN CENTRAL CONTROL ROOM.
2. ALL MEASUREMENTS ARE REFERENCED FROM THE BOTTOM OF THE SUMP PIT
3. * BEST ESTIMATE OF PUMP ACTUATION POINTS PRIOR TO 10/17/80.



EXISTING CONTAINMENT SUMP AND REACTOR CAVITY



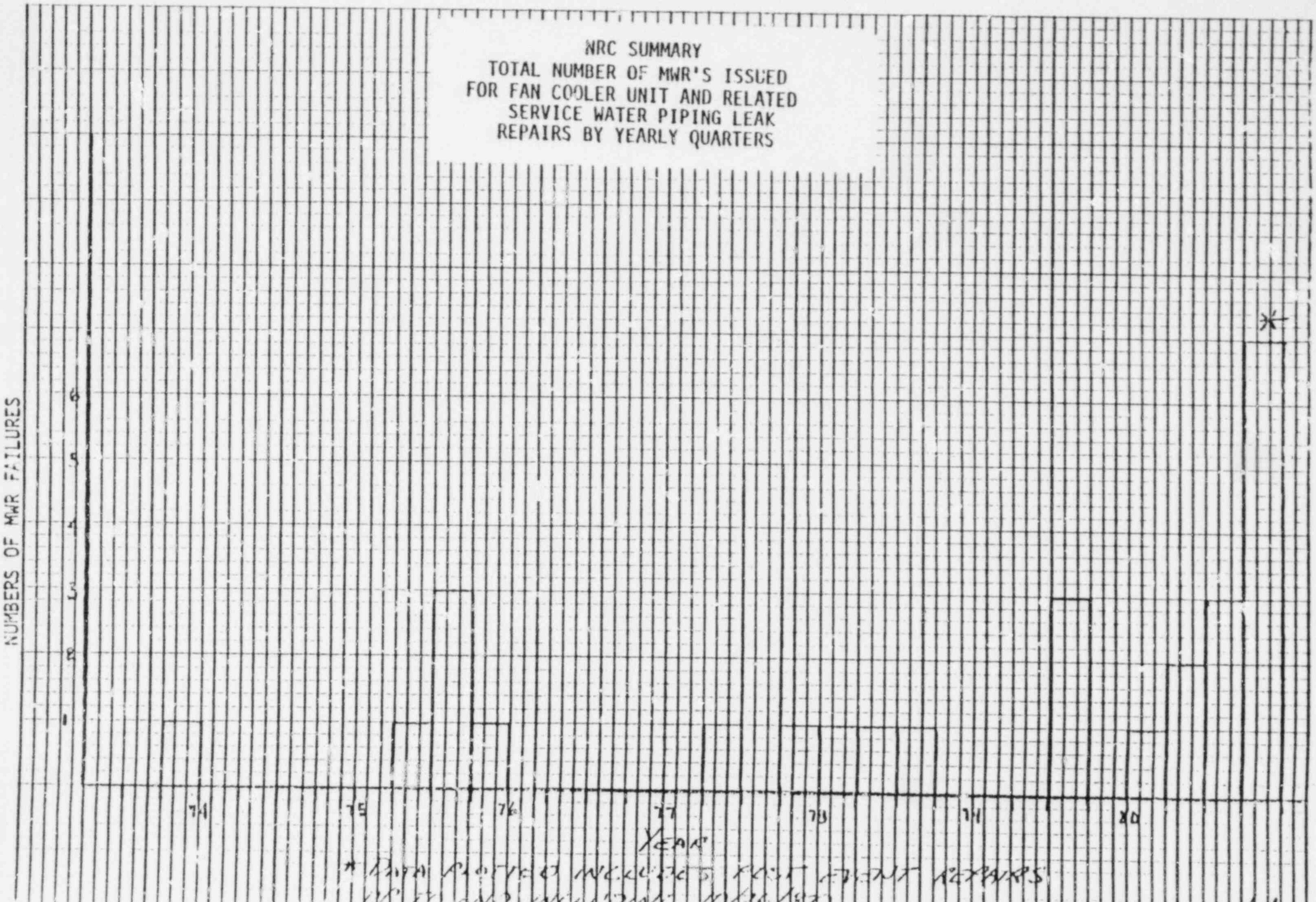
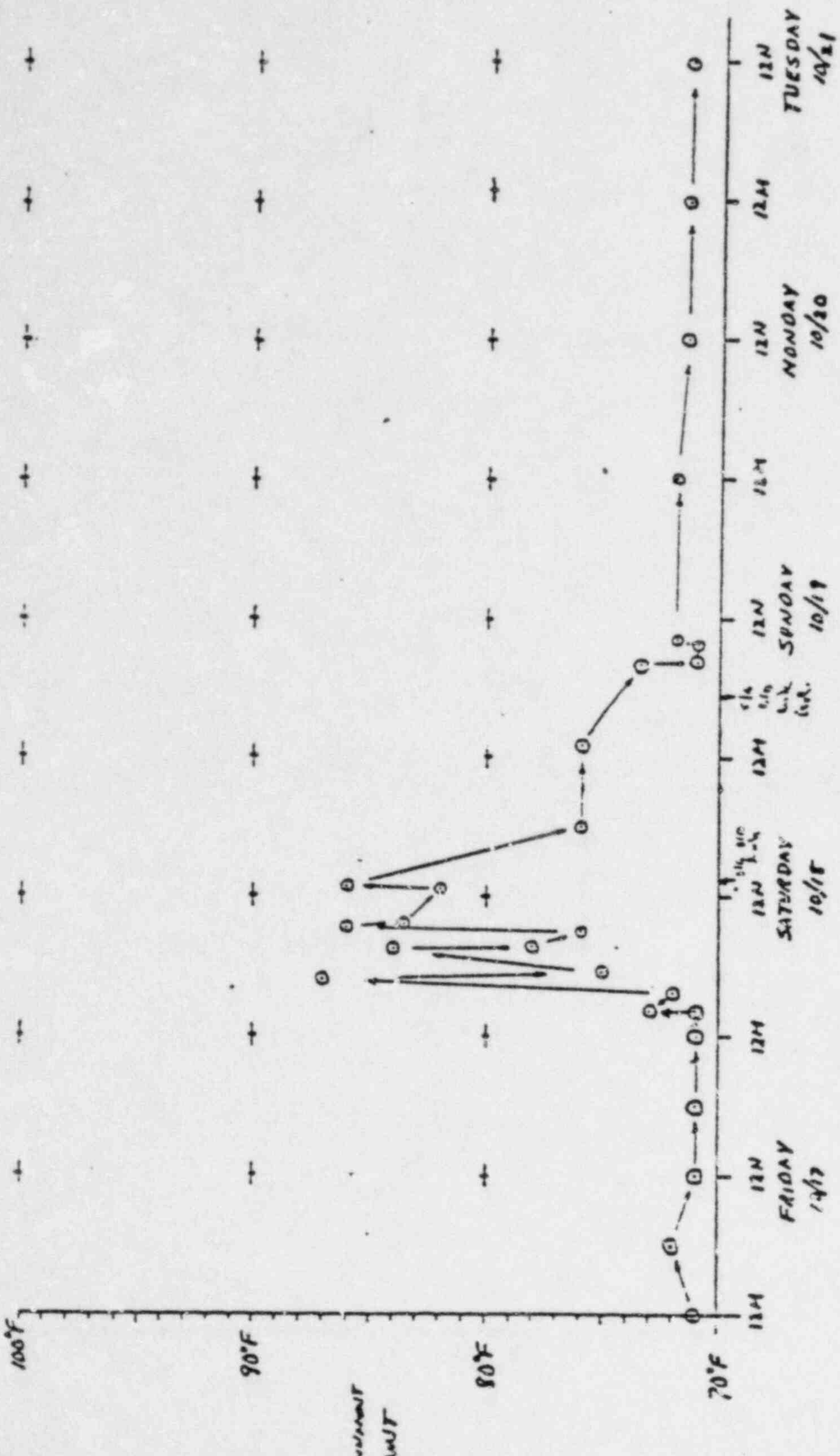

NRC SUMMARY
TOTAL NUMBER OF MWR'S ISSUED
FOR FAN COOLER UNIT AND RELATED
SERVICE WATER PIPING LEAK
REPAIRS BY YEARLY QUARTERS
NUMBERS OF MWR FAILURES
1
2
3
4
5
6
74
75
76
77
78
79
80
YEAR
*

Figure 5

V.C. DEWPOINT TEMPERATURE VERSUS TIME



FAN COOLER UNIT/ SERVICE WATER LEAK CATEGORIZATION

FAN COOLER UNIT	STUB-TUBE BRAZING FAILURES	TUBE FAILURES	FLEX HOSE FAILURES	CEMENT-LINED PIPE FAILURES	PREVIOUS REPAIR FAILURES	FIELD REPLACEMENT S.S. WELD FAILURES	BRAZED JOINTS OTHER THAN STUB TUBE-FAILURES	TOTAL CORROSION AND JOINING FAILURES
21	2	1						3
22			2	1				3
23		2		3		2	2	9
24	1			2	3		1	7
25	2	2(1)	1	2	3			10
TOTAL	5	5	3	8	6	[illegible]	3	32

NOTE: (1) INCLUDES 5 TUBE FAILURES IN ONE TUBE AS ONE (1) FAILURE

FIGURE 6

ACRONYMS AND UNITS OF MEASURE

1. ACRONYMS

C.O.E	Chief Operations Engineer
F.C.U.	Fan Cooler Unit
I&C	Instrumentation & Control
IAL	Immediate Action Letter
IE:HQ	Office of Inspection and Enforcement Headquarters
IP 2	Indian Point 2
HAZ	Heat Affected Zone
M.S.I.V.	Main Steam Isolation Valve
MWR	Maintenance Work Requests
NaCl	Sodium Chloride
N.D.E.	Non-Destructive Examination
NI	Nuclear Instrumentation
N.P.G.	Nuclear Power Generation
N.P.O	Nuclear Plant Operator
N.R.C.	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
O.C.C.	Operations Control Center
Q.C.I.R.	Quality Control Inspection Report
P.M.	Plant Manager
P.W.H.T.	Post Weld Heat Treatment
R.C.S.	Reactor Coolant System
R.V.	Reactor Vessel
S/G	Steam Generator
S.F.S.	Support Facility Supervisor
S.W.S.	Senior Watch Supervisor

Tavg	Average Reactor Coolant System Temperature
T.E.D.	Technical Engineering Director
T.S.	Technical Specification
V.C.	Vapor Containment
V.P.	Vice President
W.H.U.T.	Waste Hold-up Tank

2. UNITS OF MEASUREMENTS

gpm	gallon per minute
mg	milligrams
mg/dm^2	milligrams per decimeter squared
mls	milliliters
MWe	Megawatts-electric
ppm	parts per million
psig	pounds per square inch-gage
uc/cc	microcuries/cubic centimeter
^oF	degrees Fahrenheit
%	percent
#	number

ENCLOSURE 1

NRC SEQUENCE OF EVENTS
INDIAN POINT 2
WATER LEAKAGE INTO CONTAINMENT

WEDNESDAY, OCTOBER 1, 1980

PLANT STATUS: Reactor at 100% power, Tavg at 548°F, Boron Concentration at 185 PPM, Turbine Generator at 820 MWE, Vapor Containment at 108°F and 0.1 psig.

--- Vapor Containment (V.C.) entered while at 100% power to repair leaks on Fan Cooler Unit (F.C.U.) #25. These repairs were prompted by a desire to reduce the measured inleakage to the Waste Holdup Tank (W.H.U.T.).

FRIDAY, OCTOBER 3, 1980

PLANT STATUS: Reactor at 100% power, Tavg at 548°F, Boron Concentration at 180 PPM, Turbine Generator at 820 MWe, Vapor Containment at 111°F and 0.4 psig.

--- V.C. entered while at power to repair leaks on F.C.U. #21. During entry, the floats, associated with at least one V.C. sump pump controller and both V.C. sump level indication systems were lifted by hand to check their freedom of operations. No apparent problems noted.

--- Subsequent measured inleakages to the W.H.U.T. showed a marked reduction to historical values. The V.C. sump level indication system continued to show a water level between the 45 inch and 91 inch level switches on one instrument stalk, but now showed a water level between the 51 inch and 97 inch level switch on the other stalk. All F.C.U. weir levels indicated below 4 inches.

TUESDAY, OCTOBER 14, 1980

PLANT STATUS: Reactor at 100% power, Tavg at 549°F, Boron Concentration at 145 PPM, Turbine Generator at 830 MWe, Vapor Containment at 111°F and 0 psig.

--- High weir level alarm received on F.C.U. #22, reading above 7 inches. Licensee evaluated this alarm and declared the alarm channel inoperable. This response action was based on no observed increase in V.C. radiation, particulate, dew point or sump level detector readings; no observed increase in calculated W.H.U.T. inleakage or reactor coolant system outleakage; and, no observed change in F.C.U. #22 weir level indication, when operators closed the Service Water supply and return lines to F.C.U. #22. (Note: The Service Water return line isolation valve has since been found to leak excessively).

THURSDAY, OCTOBER 16, 1980

PLANT STATUS: Reactor at 100% power, Tavg at 549°F, Boron Concentration at 160 PPM, Turbine Generator at 830 MWe, Vapor Containment at 113°F and 0.2 psig.

0940 Started #22 Containment Spray pump for a surveillance test.

1008 Secured #22 Containment Spray pump. Test acceptance criteria met.

1645 Notified by consultants, Woodward & Clyde, that there was a possible earthquake at 1302 hours on 10/15/80, in the vicinity of the Croton Reservoir. The event was too small to determine the exact location or to register a number on their scale. However, motion was detected by some of their instruments and no blasting was known to have occurred in that area at that time (the Croton Reservoir is about 12 miles from Indian Point at its nearest point).

Notified required personnel and agencies.

1705 Completed check of Control Room and plant for evidence of damage to equipment and structures; none found.

1707 Notified by Unit #3 that no motion was detected by their seismic recorders.

1708 Notified NRC via hot line of potential earthquake report, response actions and results.

1733 Notified NRC Resident Inspector of potential earthquake report, response actions and results.

FRIDAY, OCTOBER 17, 1980

PLANT STATUS:	Reactor at 100% power, Tavg at 549°F, Turbine Generator load at 820 MWe, Boron Concentration at 130 PPM, Vapor Containment at 110°F and 0.3 psig.
Approx. 0030	Received high alarm on Nuclear Instrument Power Range Channel N42-Axial Flux Offset.
Approx. 0030	Operators noted nightly heat balance readings appeared abnormal. Performed quadrant power tilt calculations. Tilt indicated 1.02 upper and 1.03 lower. Requested I&C to check instrumentation. Channel N42 indicated high positive axial flux tilt. Suspected bad power range channel. Performed Quadrant tilt calculations on 1/2 hour basis.
Approx. 0045	Chief Operations Engineer was called at his home and and informed of the problem with Channel N42. He then called the Plant Manager and informed him of the problem.
Approx. 0100	Reduced load from 100 percent due to Nuclear Instrument System problems in attempt to correct flux tilt.
---	Reactor Engineer was requested to come to plant by the Senior Watch Supervisor (S.W.S.). Was informed bottom detector on Nuclear Instrument Channel N42 was reading less than expected.
0210+	Load reduced to about 90 percent.
Approx. 0300	Reactor Engineer arrived onsite.
Approx. 0300	Performed check on channel N42; all electronic circuits in Control Room appeared acceptable.
Approx. 0325	Performed incore flux map.
0355	Determined flux distribution was normal and concluded instrument channel had failed. Nuclear Instrument Power Range Channel N42 was declared inoperable.
---	S.W.S. called the Chief Operations Engineer at home and requested he get permission to operate above 70 percent power with one Power Range Nuclear Instrument Channel inoperable, as is required by licensee's procedures.

0400	Removed control power fuses from Channel N42. This caused a rapid indicated power decrease in the N42 core quadrant, resulting in a rod drop alarm and turbine runback actuation (due to rod drop protection circuitry). Experienced Turbine Runback from 700 MWe to 500 MWe.
---	During telephone discussion, the Plant Manager gave permission to the Chief Operations Engineer to operate up to 100 percent power with one Power Range Nuclear Instrument Channel out of service.
---	Licensee's Operations Control Center (O.C.C.) and Chief Operations Engineer informed of runback.
0408	Axial flux offset alarm.
0415	High Tavg alarm.
0418	Tavg increased with lower steam demand and control rods in manual. Decided movement of control rods undesirable. Dispatched operators to local turbine generator controls. Operator turned the load limiter in the wrong direction, driving the turbine generator load from 500 MWe to about 100 MWe. Experienced a Reactor Trip from 70% power. First out annunciator indicated trip from Low Low Steam Generator Level #23. Computer sequence of events log indicated Reactor trip due to High Pressurizer Pressure.
---	Chief Operations Engineer and the O.C.C. were informed by the S.W.S. by telephone of the trip.
---	During telephone discussion, the Plant Manager agreed with the Chief Operations Engineer to start up plant with only three power range nuclear instrument channels operable. Each reportedly was confident the cause of the trip was understood and that a delay in startup was not warranted. The decision to promptly return to power was possibly tempered by the knowledge that xenon buildup would prevent return to criticality if actions were delayed, due to minimal excess reactivity left in core.
0435	Licensee called NRC on "Hot Line." IE:HQ log indicates: trip from 60% power caused by failure of power range channel #42; failure caused turbine runback, and steam generator level oscillation causing reactor trip; all systems operated as expected; and plant may go back to power with channel tripped.

	Review of IE:HQ tapes indicates plant further reported no safety injection or radioactivity release occurred.
Approx. 0451	Completed critical rod estimate. Reactor Trip breakers shut.
0540	Began pulling rods to go critical.
0600	Reactor Critical. O.C.C. informed.
0620	V.P.-Power Generation was updated on events of the morning by the O.C.C.
---	Holding approximately 3% power, diluting to compensate for xenon buildup.
Approx. 0830	During a telephone discussion, the licensee's Techncial Engineering Director informed the NRC Resident Inspector (RI) of the first reactor trip. Subsequently, the licensee again called the Resident, confirming they had reported the trip to NRC via the emergency phone.
Approx. 0840	NRC Resident Inspector informed his Section Chief of first reactor trip with reactor now critical.
Approx. 0847	I&C Department working on power range nuclear instrumentation. Checks of Channel N42 show sluggish response. Technician decided to do a comparison check. Took all of Channel N42 trips out of the circuit with the exception of Overpower Delta "T" and Overtemperature Delta "T". Reactor tripped on Overpower Delta "T" (2 out of 4 logic).
---	Plant Manager agreed with Chief Operations Engineer to start up plant. Each reportedly was confident the cause of the trip was understood and that a delay in startup was not warranted.
---	Prepared estimated critical position (Bank D at 145 steps).
Approx. 0900	I&C Engineer learned of grounded nuclear instrument detector on Channel N42. Detector signal cable center conductor to ground and center conductor to shield conductor resistances both read about 2000 Ohms.
0902	Reactor Trip breakers shut.
---	Pulling rods to go critical.

Approx. 0920	Licensee called NRC on "Hot Line." IE:HQ log indicates: trip from 3% power at 0850 hours; technicians repairing power range Channel N42 were careless in cabinet; tripped on Overtemperature Delta "T" Channel 42; and, returning to power. Review of IE:HQ tapes indicates plant further reported to be in hot shutdown; expecting to go critical within next hour; and, no safety injection or radioactivity release occurred.
Approx. 0930	Technical Engineering Director discussed second Reactor trip with NRC Resident Inspector.
---	Plant Manager decided to take the plant to hot shutdown to replace failed nuclear instrument detector. The decision to shutdown was reportedly influenced by the requirement to conduct daily flux maps. (with one nuclear channel inoperable), the concern for wear on the incore instrument system. (during the conduct of these procedures), the increased probability of a spurious Reactor trip (with one channel tripped), and the recognition that spare parts were available and the fix would only take a couple of hours. (since union personnel would assist in the repairs if the plant was shu).
0950	Reactor critical.
0950+	Operators directed to shutdown Reactor by the Chief Operations Engineer, who had just entered the Control Room, conveying the Plant Manager's decision.
1000	Plant Manager informed O.C.C. that failed power range detector would be replaced and that unit should be back on line by 1700 hours.
1010	Reactor Subcritical - Shutdown banks still out.
1015	Shut Main Steam Isolation Valves (M.S.I.V.s) to reduce cooldown rate. Broke condenser vacuum. One M.S.I.V. did not close fully. Operator able to close manually.
Approx. 1030	Preparations begun to enter V.C. for Channel 42 detector replacement.
Approx. 1100	Technical Engineering Director informed NRC Resident Inspector that plant had been shutdown to repair Channel N42.

Approx. 1145	During the V.C. entry the licensee planned to pull the detector in line with its removal hole, from elevation 46 feet, and replace the detector from the refueling cavity. If elevation 95 feet lights were found off, plans were to exit and regroup.
1200	V.C. entry. Eight personnel (5 I&C Technicians and 3 Health Physicists) entered. Five individuals went to elevation 95 feet and found lights out. Three individuals went to elevation 68 feet and then elevation 46 feet. On elevation 68 feet, water was seen on floor around F.C.U. #22. On elevation 46 feet, noted water coming from ceiling under F.C.U. #22 and from F.C.U. #22 weir. Floor of elevation 46 feet was noted to have several inches of water covering it.
Approx. 1210	Crew out of V.C. Report of observations was made to control room and Plant Manager. Plant Manager informed Operations personnel would investigate.
---	Operators verified isolation valves open on V.C. sump pump discharge line to the W.H.U.T.
Approx. 1230	Isolated Service Water supply and return to F.C.U. #22, due to Service Water leak.
---	NRC Resident Inspector informed Section Chief that plant was in hot shutdown to repair nuclear instrumentation.
1320	Crew back in V.C. for second attempt to install Detector N42. Planned to use flashlights on elevation 95 feet and rubber boots on elevation 46 feet.
1335	A Support Facility Supervisor (S.F.S.), a Senior Reactor Operator, entered the V.C. at the direction of the S.W.S. to investigate the water on the floor. Both V.C. sump pumps were found stopped and F.C.U. #22 was found to have a Service Water Leak. Manual actuation of both V.C. Sump Pump floats caused one pump to start. Replacement of fuses and possible resetting of the thermal overloads started the second V.C. Sump Pump.
Approx. 1345	On elevation 95 feet, crew noted high temperature and humidity in refueling cavity and steam-like vapor exiting from holes in the detector well covers. A water film covered the electrical conductors in the hole. On elevation 46 feet, noted 4 F.C.U. weirs overflowing, including F.C.U. #22 weir, at a reduced rate. A lot of water was still dripping from the elevation 46 feet overhead, under F.C.U. #22. The depth of the water on the floor inside the missile shield was found to be deeper and was characterized as 2 to 4 inches or ankle deep.

1405	S.F.S. exited V.C. to obtain tools to inspect the leak on F.C.U. #22 Service Water return line. V.C. Sump Pump #29 had been found with two blown fuses and V.C. Sump Pump #210 had malfunctioned due to a cocked float assembly.
1430	S.F.S. returned to V.C. and removed the insulation from F.C.U. #22 Service Water return line. Hole found in 10 inch pipe at a weld. The S.F.S. exited the V.C. 20 minutes later and informed the Control Room of his findings.
Approx. 1430	Plant Manager and Control Room notified by the I&C Engineer of his inability to replace Channel N42 detector due to hot-humid vapor issuing from detector well.
---	During a meeting in the Plant Manager's office the Technical Engineering Director questioned what water level had been observed on the elevation 46 feet floor. When informed that the level had reached only 2 to 4 inches, he reportedly indicated the curb on the openings leading to the Reactor Vessel Pit was 6 inches tall and it was then concluded that water could not have flowed into the pit. During the same meeting it was agreed the Technical Engineering Director would inform the NRC Resident Inspector.
---	Discussions with licensee management indicated no manager believed there existed a requirement to notify NRC of the Service Water leakage collected on the V.C. floor; nor could anyone even recall a discussion of the potential need to make such a report.
1522	The Technical Engineering Director attempted to contact the NRC Resident Inspector. Left message on answering machine requesting a return call. No reason for the call was recorded. Licensee reportedly intended to inform Resident of the M.S.I.V. closure failure and the discovery of a couple of inches of Service Water on the V.C. floor.
Approx. 1600	Maintenance made V.C. entry to repair F.C.U. #22 using a rubber backed stainless steel sleeve clamp for the 10 inch service water outlet line leak.

---	Licensee planned to return to power before 2300 hours with three operable power range nuclear instruments. Operators directed to keep on top of V.C. sump pumping rate.
---	V.P. Power Generation notified by Plant Manager of F.C.U. leaks.
Approx. 1800	S.F.S entered V.C. to verify no water had gotten into Reactor Vessel Pit. Found water in Pit about 4 feet below locked grating on elevation 46 feet. (This is first reported evidence of water in Reactor Vessel Pit.) The S.F.S. checked the lights for the Reactor Vessel Pit Sump Pumps and believed one was lit and one was out. He further observed an acceptable leak repair test of F.C.U. #22, noted a water leak from near F.C.U. #23, and then left the V.C.
Approx. 1830	S.F.S. notified Chief Operations Engineer and Control Room of his findings.
Approx. 1900	Plant Manager informed by the Chief Operations Engineer that the Reactor Vessel Pit was flooded, that leaks on the F.C.U.'s were being repaired, and that the V.C. Sump Pumps were pumping the water out. This information was not passed on to the V.P.-Power Generation at this time.
Approx. 1945	Cleared permit and started F.C.U. #22.
Approx. 1947	Tagged out F.C.U. #23 for leak repairs.
Approx. 2045	Licensee gathered equipment to install and operate portable submersible pumps. A Reactor Operator Trainee entered the V.C. to determine if the Reactor Vessel Pit Sump Pumps were running. Found pump with the moisture detector alarm lit (falsely believed to indicate pump running) to have power downstream of the line fuses. Trainee hung two strings with weights attached; one touched water surface and one extended several feet below the water level. Trainee reported the Reactor Vessel Pit water level had dropped 4 inches during his entry. This convinced the Trainee that the Reactor Vessel Pit Sump Pumps were pumping.
Approx. 2240	V.C. sump isolated. W.H.U.T. being transferred to Unit 1.

Approx. 0340	Average of Dew Point temperatures had decayed to about 72°F, but now turned and climbed to about 86°F, over a period of about one hour.
Approx. 0445	Average of Dew Point temperatures had peaked at about 86°F and started rapid decrease to about 76°F, over next 45 minutes.
Approx. 0530	Average of Dew Point temperatures bottomed at about 76°F and now started less rapid rise to about 84°F, over a period of two hours.
Approx. 0530	V.C. entry party noted Reactor Vessel Pit water level decreasing.
---	Operator instructed to compute estimated critical position for 0900 hours on 10/18/80.
Approx. 0730	Average of Dew Point temperature peaked at about 84°F and then began slow decrease to about 77°F, over a period of about one and one half hours.
0730+	Repaired V.C. sump floats, which had become cocked and stuck again, and inspected the Reactor Vessel pit. (Water level 13 ladder rungs down, elevation 34 feet.)
Approx. 0900	Average of Dew Point temperatures jumped from about 77°F to about 82°F, where it remained for about three and one half hours.
1210	O.C.C. informed unit expected to go critical approximately 1400 hours.
1227	S.W.S. toured containment and noted water level in Reactor Vessel Pit just above the portable sump pump on the intermediate level. The portable pump was pumping. Found leak on #21 S/G blowdown line and #25 F.C.U. S.W.S. exited the V.C. at about 1400 hours.
Approx. 1240	Average of Dew Point temperatures jumped to about 86°F, where it remained for about one and one half hours.
Approx. 1300	#23 F.C.U. Service Water flow resumed.

Approx. 0340	Average of Dew Point temperatures had decayed to about 72°F, but now turned and climbed to about 86°F, over a period of about one hour.
Approx. 0445	Average of Dew Point temperatures had peaked at about 86°F and started rapid decrease to about 76°F, over next 45 minutes.
Approx. 0530	Average of Dew Point temperatures bottomed at about 76°F and now started less rapid rise to about 84°F, over a period of two hours.
Approx. 0530	V.C. entry party noted Reactor Vessel Pit water level decreasing.
---	Operator instructed to compute estimated critical position for 0900 hours on 10/18/80.
Approx. 0730	Average of Dew Point temperature peaked at about 84°F and then began slow decrease to about 77°F, over a period of about one and one half hours.
0730+	Repaired V.C. sump floats, which had become cocked and stuck again, and inspected the Reactor Vessel pit. (Water level 13 ladder rungs down, elevation 34 feet.)
Approx. 0900	Average of Dew Point temperatures jumped from about 77°F to about 82°F, where it remained for about three and one half hours.
1210	O.C.C. informed unit expected to go critical approximately 1400 hours.
1227	S.W.S. toured containment and noted water level in Reactor Vessel Pit just above the portable sump pump on the intermediate level. The portable pump was pumping. Found leak on #21 S/G blowdown line and #25 F.C.U. S.W.S. exited the V.C. at about 1400 hours.
Approx. 1240	Average of Dew Point temperatures jumped to about 86°F, where it remained for about one and one half hours.
Approx. 1300	#23 F.C.U. Service Water flow resumed.

SUNDAY, OCTOBER 19, 1980

PLANT STATUS: Reactor subcritical in a hot shutdown mode awaiting return to power. The Va or Containment was closed but unlocked with pressure relieving in progress. The water in the W.H.U.T. was being transferred to Unit 1.

Approx. 0100 — Air operated pump lowered about 5 feet below intermediate landing of Reactor Vessel Pit. Water level just above intermediate landing. Elevation 46 feet floor reportedly dry with some puddles.

0250 — Commenced work on F.C.U. #21 cooler leak.

0400 — Started F.C.U. #25 for test following leak repairs.

Approx. 0555 — Opened inlet valve to F.C.U. #21.

Approx. 0600 — V.C. entry made to repair portable submersible pump in Vessel Pit, which had stopped. Water level at intermediate landing grating. Could not fix pump. Lubricator had run out of oil and pump had seized.

0625 — Started F.C.U. #21.

--- — Repairs completed to V.C. Sump Pump float operated controllers.

0917 — S.W.S. toured V.C. W.H.U.T. and V.C. Sump were full. One to two inches of water found on floor of elevation 46 feet. Found float on V.C. Sump Pump's controller loose. Reactor Vessel Pit Intermediate Landing level found awash. No evidence that either installed Reactor Vessel Pit permanent sump pump was working. Left V.C. at 1003 hours.

Approx. 0930 — Repaired float ball for V.C. Sump Pump controller.

Approx. 1030 — S.W.S. and Chief Operations Engineer decided to drill hole in Reactor Vessel Pit Sump Pump's discharge line to preclude siphoning V.C. sump to Reactor Vessel Pit.

1145 — V.P. Power Generation called O.C.C. for update on status of pla.ts.

--- — V.P. Power Generation called S.W.S., learned water found in Reactor Vessel Pit, believed this was connected with Steam Generator Blowdown Line leak reported earlier, and offered to assist in finding additional pumps.

PLANT STATUS:	Reactor subcritical in a hot shutdown mode awaiting return to power. The Vapor Containment was closed but unlocked with pressure relieving in progress. The water in the W.H.U.T. was being transferred to Unit 1.
Approx. 0100	Air operated pump lowered about 5 feet below intermediate landing of Reactor Vessel Pit. Water level just above intermediate landing. Elevation 46 feet floor reportedly dry with some puddles.
0250	Commenced work on F.C.U. #21 cooler leak.
0400	Started F.C.U. #25 for test following leak repairs.
Approx. 0555	Opened inlet valve to F.C.U. #21.
Approx. 0600	V.C. entry made to repair portable submersible pump in Vessel Pit, which had stopped Water level at intermediate landing grating. Could not fix pump. Lubricator had run out of oil and pump had seized.
0625	Started F.C.U. #21.
---	Repairs completed to V.C. Sump Pump float operated controllers.
0917	S.W.S. toured V.C. W.H.U.T. and V.C. Sump were full. One to two inches of water found on floor of elevation 46 feet. Found float on V.C. Sump Pump's controller loose. Reactor Vessel Pit Intermediate Landing level found awash. No evidence that either installed Reactor Vessel Pit permanent sump pump was working. Left V.C. at 1003 hours.
Approx. 0930	Repaired float ball for V.C. Sump Pump controller.
Approx. 1030	S.W.S. and Chief Operations Engineer decided to drill hole in Reactor Vessel Pit Sump Pump's discharge line to preclude siphoning V.C. sump to Reactor Vessel Pit.
1145	V.P. Power Generation called O.C.C. for update on status of plants.
---	V.P. Power Generation called S.W.S., learned water found in Reactor Vessel Pit, believed this was connected with Steam Generator Blowdown Line leak reported earlier, and offered to assist in finding additional pumps.

2200	Opened Condenser Vacuum Breakers.
2230	Second Reactor Vessel Pit Portable Pump still not working. N.P.O. sent in to correct improper hook up. Water level about 4 feet below intermediate landing. First pump still working.
Approx. 2330	Opened inlet valve on F.C.U. #25.

PLANT STATUS:	Reactor subcritical in a hot shutdown mode awaiting return to power. The Vapor Containment airlock door was closed with people working inside on F.C.U.'s.
Approx. 0025	Completed repairs on F.C.U. #25 and valved it into service.
0125	Started F.C.U. #25 for test. Showed no excessive leakage.
Approx. 0115	Second Reactor Vessel Pit portable pump off again. Water at 14th rung below intermediate landing (elev. 19' 8"; 4" of water on bottom of pit).
---	V.C. Sump pumps isolation valves closed.
Approx. 0145	Opened V.C. Sump isolation valves. W.H.U.T. level at 86%.
Approx. 0205	V.C. Sump isolation valves closed with W.H.U.T. level at 94%.
0305	During V.C. entry found water on floor outside missile barrier, where it had previously (prior to midnight) been reported dry. Operators went into V.C. to remove portable submersible pumps if water level was found below incore instrument conduits in Reactor Vessel Pit. Otherwise, were directed to add oil to the portable submersible pumps and continue pumping the Reactor Vessel Pit. Water level was found below conduits in pit.
0530	O.C.C. informed by S.W.S. that the shift was closing out the Vapor Containment, was preparing to go critical, and expected to be on line by 1000 hours.
Approx. 0530	Reactor Vessel Pit essentially dry. Two portable submersible pumps had been removed from the Reactor Vessel Pit and placed on floor outside missile barrier on elevation 46 feet floor.
Approx. 0610	Performed V.C. Closeout. V.C. sump pumped down all the way; final check on all F.C.U.'s found no leaks on cooling coils, motor coolers, or external piping. Removed air hoses from Reactor Vessel Pit and closed and locked the grating. Recommended entry be made in next 24 hours to check for leaks. Water was observed to still be flowing from F.C.U. weir #22. V.C. sump isolation valves were closed with W.H.U.T. level at 95%.

Approx. 0630	Commenced control rod withdrawal for normal startup.
0650	Reactor Critical. O.C.C. informed.
0700+	W.H.U.T. still being transferred to Unit 1.
Approx. 0730	Ansaphone in NRC Resident Inspector's office interrogated. Message from licensee indicated: Time 3:22 p.m.; 10/17; requests return call. No reason was given.
Approx. 0745	NRC Resident Inspector returned call to Technical Engineering Director, found him out, and requested call back.
Approx. 0800	Manager, Nuclear Power Generation (N.P.G.), who had been on vacation since 10/14/80, arrived on site and was briefed on plant status.
Approx. 0830	Manager, N.P G. made decision to shutdown, based on concern about chlorides on stainless steel incore instrument conduits. V.P.-Power Generation was updated on plant status and concurred in decision to shutdown.
---	Licensee initiated effort to compute volume of water pumped from V.C.. Chemistry and Radiation Safety Director was instructed to swipe survey incore instrument conduits to determine level of flooding in Reactor Vessel Pit.
0955	Reactor manually shutdown from less than 1% power. Turbine never taken off turning gear.
Approx. 1010	Opened V.C. sump isolation valves with W.H.U.T. level at 80%.
Approx. 1050	Closed V.C. sump isolation valves with W.H.U.T. level at 95%.
1110	Made preparations for V.C. entry.
Approx. 1115	Licensee returned call to NRC Resident Inspector. Stated that some water was found on containment floor over weekend and plant was critical this morning, but now in hot standby.

Approx. 1200	Licensee sampled water in Reactor Vessel Pit; found 3400 ppm NaCl. Licensee swiped incore instrument conduits; found levels from 0.025 to 1.53 mg/100 cm^2 of chlorides, from point above elevation 46 feet to Reactor Vessel insulation, with results increasing as Reactor Vessel was approached. The highest observed level was associated with an encrustation, believed by the licensee on 10/20/80 to be unrelated to this flooding event.
---	V.P.-Engineering notified of water on V.C. floor and in the Reactor Vessel Pit.
1300	Crew out of V.C.
---	Manager, N.P.G. informed NRC Resident Inspector that preliminary water inventory balances indicated about 45,000 gallons of water were pumped from the V.C.
Approx. 1605	NRC Resident Inspector called Region I; notified Acting Section Chief of V.C. flooding, that preliminary inventory calculations indicated 45,000 gals. of liquid were removed from the V.C.. Question of potential wetting of Reactor Vessel was raised by Region I.
Approx. 1635	Shut V.C. sump isolation valves with W.H.U.T. level 96%.
1645	Region I called licensee. Licensee indicated Reactor Vessel was not wetted. Chief Operations Engineer and Assistant Chief Field Engineer reportedly performing calculations to support these contentions. Plant in hot shutdown. Information requested from licensee on restart plans.
1707	Region I called NRC Resident Inspector to discuss open questions.
Approx. 1710	Region I called IE:HQ to discuss open questions.

1720	Region I called licensee. Received licensee commitment to not restart without first providing NRC four hours warning. Discussed open questions with licensee. (1) Was Reactor Vessel wetted? (2) If so, what effect on vessel? (3) What corrective actions prevent reoccurrence? (4) What plans exist for inspection of stainless steel conduits?
Approx. 1830	Opened V.C. airlock for entry.
Approx. 1900	Closed V.C.
---	Chief Operations Engineer recomputed best estimate of water pumped from V.C., to be about 106,000 gallons, which the licensee believed would still not wet reactor vessel.
Approx. 2100	Nuclear side N.P.O. entered V.C. to string hoses for cleaning. Unisolated city water to V.C.
2300+	(1) V.C. sump isolation valve closed. (2) W.H.U.T. still being transferred to Unit 1.

TUESDAY, OCTOBER 21, 1980

PLANT STATUS: Reactor subcritical in a hot shutdown mode awaiting return to power. The Vapor Containment was closed but unlocked. People working in V.C. City Water had been valved into the Vapor Containment for cleaning.

0100+	Opened V.C. sump isolation valves.
Approx. 0330	Licensee took ten additional swipes of incore instrument conduits, finding 0.065 to 0.605 mg/100 cm^2 of chlorides. Licensee sampled stainless steel wool from the Reactor Vessel insultation; found 0.085 mg chlorides/gram of material.
0430	Nuclear side N.P.O. toured V.C., found elevation 46 feet floor dry, except for low area puddles. V.C. sump full. Maintenance working in reactor vessel cavity.
0440+	Opened V.C. sump isolation valves.
Approx. 0600	O.C.C. informed outage reason changed to chloride cleanup and that unit expected to return on 10/23/80.
0605	NRC IE:HQ Duty Officer called for Plant Status.
Approx. 0800	Sampled V.C. Sump.
0845	Region I called by NRC Resident Inspector; informed of plant status and plans. Immediate Action Letter questions discussed.
Approx. 0900	Started pumping V.C. sump.
Approx. 0930	Spare N.P.C. tagged out the Reactor Vessel Pit Sump Pump controls and fuses. Secured pumping V.C. sump. W.H.U.T. level at 90%.
Approx. 0942	Licensee swiped insulation sleeve for a Reactor Vessel Incore Instrument stub tube; findings 2.9 mg/100 cm^2 of chlorides.
1134	PNO-I-80-154, Containment Fan Cooler Service Water Leak, issued by Region I.
Approx. 1300	Licensee took three swipes in and around insulation sleeve for Reactor Vessel Incore Instrument stub tubes; finding 0.44 to 1.66 mg/100 cm^2 of chlorides.

---	Licensee cleaned incore instrument stainless steel conduits in Reactor Vessel Pit.
Approx. 1430	Opened V.C. sump isolation valves.
1430+	Completed certain precritical checks.
---	Cleared Work Permit on power range N42 detector. Conducted various tests, calibrations and alignments of Nuclear Instrument Channel N42. Inspection of the N42 detector signal and power lead connectors, located in the detector well, found drops of water within the taped connectors. The detector was replaced.
1542	Region I called licensee to solicit commitments per Immediate Action Letter IAL 80-41.
---	Manager, N.P.G. decided to proceed to cold shutdown; thereby, allowing the removal of Reactor Vessel insulation, and the swiping and cleaning of the exposed surfaces.
---	Licensee recognized lacked proof that Reactor Vessel was not wetted.
---	Licensee directed operators to cool Reactor Coolant System (R.C.S.) to cold shutdown.
1659	NRC Resident Inspector entered V.C. for inspection of conditions in Reactor Vessel Pit. Noted overhead lights out, white substance (like salt) on ventilation duct and around seams of Reactor Vessel Mirror Insulation.
2000	Commenced borating Reactor Coolant System to Boron concentration required for cold shutdown.
Approx. 2020	Inserted shutdown Bank A by tripping Reactor.

WEDNESDAY, OCTOBER 22, 1980

PLANT STATUS:	Reactor subcritical and being cooled down to cold shutdown mode. Borating to cold shutdown condition. All control rods inserted into the Reactor. Purging the V.C. W.H.U.T. water being transferred to Unit 1.
Approx. 0045	Maintenance entered V.C. to replace both Reactor Vessel Pit electrical sump pumps.
0530	Blocked Safety Injection.
0615	NRC IE:HQ Duty Officer called to determine Plant Status.
0700+	(1) Still proceeding to cold shutdown. (2) W.H.U.T. being transferred to Unit 1.
Approx. 0845	#21 Residual Heat Removal (R.H.R.) pump in service.
---	IAL 80-41 issued by Region I.
1500	Investigation team dispatched from Region I and other sites.
Approx. 1600	Plant reached Cold Shutdown.
1600	Licensee performed seven swipes of Reactor Vessel shell, mirror insulation and various Reactor Vessel Pit components; finding less than 0.005 mg/100 cm^2 of chlorides. This followed the first opening of the Reactor Vessel Mirror Insulation by the removal of a small square plate located at dead center of the bottom of the Lower Reactor Vessel Head. The swipe results reinforced the licensee's belief that the Reactor Vessel had not been wetted.
1700	Licensee determine boildown residue of 50 mls of Hudson River Water (4620 ppm NaCl) yielded a swipe result of 43.6 mg/100 cm^2 of chlorides.
1900	Investigation team assembled on site and were briefed by Resident Inspectors.
2000	Investigation team conducted first interview.

THURSDAY, OCTOBER 23, 1980

PLANT STATUS: Reactor now in cold shutdown with multiple activities progressing within the Vapor Containment. The Containment was open.

0000+ Licensee immersed stainless steel plate in river water, dried the plate and swiped it. Sample results showed 1.0 mg/100 cm^2 of chloride.

0430 Licensee swiped five locations on Reactor Vessel surfaces now exposed by removed mirror insulation. Sample results later showed chloride contamination levels of 19.0 to 41.0 mg/100 cm^2. This followed removal of a circular piece of mirror insulation, about two foot in diameter, located dead center on the lower Reactor Vessel head. These results appeared to contradict licensee's belief that the Reactor Vessel was not wetted.

0730 Investigation Team met with licensee to discuss scope and duration of investigation, scope of assignment for each investigator, and current status of plant, licensee's investigation, and plans for return to operations.

0900 Licensee repeated earlier boildown and swipe test of 50 mls of river water. Swipe showed 49.0 mg/100 cm^2 of chlorides.

1000 Licensee performed an investigation team. An analysis of recirculation sump water as requested by the investigation team. Sample showed 3400 ppm NaCl, 30 ppm Boron and 2.8E-3 uc/cc of activity.

1350 Manager, N.P.G. informed investigators that the current estimate of water pumped from the V.C. was 85,000 gallons and that the licensee still believed no water reached the Reactor Vessel.

Approx. 1520 Licensee informed investigation team that they had received report from an S.W.S. that water level may have approached elevation 46 feet grating.

Approx. 1530 Licensee informed investigation team of identities of licensee employees who report to have seen water level within one to four feet of elevation 46 feet grating.

1700 Licensee swiped ten locations in reactor vessel pit. Samples would later show chloride levels from 0.08 to 25 mg/100 cm^2.

FRIDAY, OCTOBER 24, 1980

PLANT STATUS:	Reactor now in cold shutdown with multiple activities progressing within the Vapor Containment. The Containment was open.
0230	Licensee swiped five reactor vessel locations newly exposed on lower hemisphere as insulation was removed. Sample results later show 31 to 170 mg/100 cm^2. This followed removal of the first four pie shaped pieces of mirror insulation on the Lower Reactor Vessel Head.
1020	Licensee called Resident Inspector Office. Informed investigation team that licensee had determined that deposits on Reactor Vessel were definitely residue from evaporated river water.
Approx. 1200	Licensee met with investigation team. Investigation team was informed that the licensee believed about 9 feet of the Reactor Vessel was covered with river water, while in hot shutdown. The status of the plant, licensee's investigation and schedule for corrective actions were discussed.
Approx. 1800	Information Notice 80-07 on the Indian Point 1 incident issued by NRC.

ENCLOSURE 2

OUTSTANDING LICENSEE SUBMITTALS TO NRC

1. Reactor Vessel Stress Analysis Report
2. Reactor Vessel Mirror Insultation Test Report
3. Reactor Trip Cause Identification System Evaluation Report
4. Shift Technical Advisor Performance and Activities Evaluation Report
5. Vapor Containment Dew Point Recorder Trace Evaluation Report
6. Steam Vapor Leakage Detection Systems Capability Report
7. Failure Analysis Program Description
8. Fan Cooler Unit Service Water Containment Isolation Valve Evaluation Report
9. Fan Cooler Unit Cooling Coil and Service Water Pipe Failure Analysis Report
10. Steam Generator Blowdown Line Failure Analysis Report
11. Vapor Containment Sump Pump Failure Analysis Report
12. Reactor Vessel Pit Sump Pump Failure Analysis Report
13. Vapor Containment Survey Evaluation Report
14. Excore Nuclear Instrumentation Evaluation Report
15. Reactor Vessel Paint Chloride Retention Report
16. Recirculation Sump Activity Level Evaluation Report
17. Reactor Vessel Pit Water Transport Path Report
18. Incore Instrument Stub Tube to Reactor Vessel Weld Failure Consequence Report
19. Modification Plans Report
20. Immediate Action Letter No. 80-41 Report

U. S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

Region I

Report No. 50-247/80-19A

Docket No. 50-247

License No. DPR-26 Priority -- Category C

Licensee: Consoldiated Edison Company of New York, Inc.

4 Irving Place

New York, New York 10003

Facility Name: Indian Point Nuclear Generating Station, Unit 2

Meeting at: King of Prussia, Pennsylvania

Meeting conducted: December 3, 1980

NRC Personnel: James M. Allan 12/4/80
J. M. Allan, Deputy Director date signed

J. C. Higgins 12/4/80
J. C. Higgins, Senior Resident Inspector, Shoreham date signed

H. B. Kister 12/4/80
H. B. Kister, Chief, Reactor Projects Section No. 4 date signed

T. T. Martin 12/4/80
T. T. Martin, Chief, Reactor Projects Section No. 3 date signed

G. Napuda 12/4/80
G. Napuda, Reactor Inspector, Nuclear Support Section No. 2 date signed

Approved by: Boyce H. Grier 12/4/80
B. H. Grier, Director date signed

Meeting Summary

A meeting was held to discuss additional factual information not previously made available to the NRC investigation Team.

Region I Form 12-1
(Rev. August 77)

Dupe PDR

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DETAILS

1. Persons Contacted

On December 3, 1980, a meeting was held at NRC Region I offices for the licensee to present new factual evidence related to the investigation of the October 17, 1980, Vapor Containment Flooding event.

a. Licensee Personnel Present

Mr. B. Brandenburg, Assistant General Counsel
Mr. K. Burke, Attorney
Mr. A. Flynn, Chief Mechanical and Maintenance Engineer
Mr. J. Halpin, Maintenance Engineer
Mr. C. Jackson, Director-Quality Assurance and Reliability
Mr. E. McGrath, Vice President-Power Generation
Mr. S. Rothstein, Consulting Engineer

b. NRC Personnel Present

Mr. J. Allan, Deputy Director, Region I
Mr. B. Grier, Director, Region I
Mr. J. Higgins, Senior Resident Inspector - Shoreham
Mr. H. Kister, Chief, Reactor Projects Section #4
Mr. T. Martin, Chief, Reactor Projects Section #3
Mr. G. Napuda, Reactor Inspector

2. Information Discussed

a. Maintenance Work Requests (M.W.R.s)

The licensee provided to the NRC investigation team summaries of seven additional M.W.R.s., related to repairs of Fan Cooler Unit (F.C.U.) Service Water leaks not previously included on their Fan Cooler Unit maintenance summary. The team reviewed the information and revised NRC Investigation Report 50-247/80-19, figures 4 and 6, to reflect the additional information.

b. Failure Analysis Report

The licensee provided to the NRC investigation team a copy of a licensee memorandum dated March 15, 1973, titled "Recirculation Fan Motor Coolers, Unit No. 2 - Indian Point." The memorandum documented the results of a failure analysis performed in early 1973 on five replaced F.C.U. Motor Heat Exchangers. During the period September 1971 to January 1973, the licensee identified excessive incidents of leakage from the Heat Exchangers, warranting their replacement. The failure analysis was performed to determine if the cause of the leakage was due to excessive cooling water flow rates or other problems. The analysis concluded the cooling water flow rate was excessive, but that the failures were due to poor design and/or assembly.

Discussion with the licensee indicates the 1973 replacement Motor Heat Exchangers were fabricated and inspected to tighter specifications, which should have eliminated leakage problems in the replacement Heat Exchangers. The licensee maintained that, in their engineering judgement, the cause of F.C.U. Cooling Coil leaks was understood, based on: their knowledge of the previous determination of the leakage cause on the F.C.U. Motor Heat Exchanger; the fact that the F.C.U. Main Cooling Coils were made by the same organization with the same specifications as the original Motor Heat Exchangers; and the similarities between some new leaks appearing on the F.C.U. Cooling Coils and those on the original Motor Heat Exchangers.

The licensee indicated he was currently unaware of any other documented failure analysis for the F.C.U. Service Water System leaks.

The NRC investigation team maintained that the licensee had failed to determine and document the cause(s) of (1) F.C.U. Motor Heat Exchanger leaks, following their discovery on the new design replacement units; of (2) F.C.U. Cooling Coil leaks, assuming but not verifying the leaks were caused by the same problems identified on the replaced Motor Heat Exchangers; of (3) F.C.U. Cooling Coil leaks, when leakage not characteristic of previous brazed joint failures of tube to tube header joints occurred; and, of (4) F.C.U. Cooling Coil tube and tube header problems, identified during the Summer 1980 boroscopic examination, which revealed additional leakage cause potential (some active corrosion sites on header, possible de-nickelfication, some active pitting sites of tubes, deposits in tubes, etc.).

c. F.C.U. Performance Perspective

The licensee provided to the NRC investigation team an approximate count of total F.C.U. Cooling Coil and Motor Heat Exchanger straight tubes (3,000) and brazed joints (18,000). The licensee maintains that the failure rate of F.C.U. components is extremely low.

The NRC investigation team acknowledged the failures shown in figure 6 of NRC Investigation Report 50-247/80-19 represent a small percentage of components available for failure, but maintains the increasing frequency of leaks, as indicated in figure 4 of the same report, should have been given over-riding consideration.

3. Proposed Technical Specifications

Mr. McGrath, Vice President-Power Generation informed the NRC investigation team that his staff was unable to meet his committed schedule for submission of proposed Technical Specifications for new, modified or effected systems, related to the October 17, 1980, Vapor Containment flooding event. Mr. McGrath revised his commitment to having the proposed Technical Specifications submitted by February 15, 1981, or plant startup, whichever is later.

ATTACHMENT

Investigation Report 50-247/80-19 Revisions

The following pages and figures of NRC Investigation Report 50-247/80-19 were revised and are attached to this meeting report.

Page 5

Date by which licensee is to submit Proposed Technical Specifications was revised to reflect current commitment.

Page 31

Bottom of page was removed, since information is duplicated on top of page 32.

Page 41

1. The statement that no failure analysis had been conducted by the licensee was revised to reflect the fact that a failure analysis was performed in 1973.

2. The subjects of discussion between the NRC inspector and the Assistant Vice President for Engineering were clarified, with an additional reference to the paragraph which provides greater detail.

3. The number of MWRs associated with F.C.U. Service Water System leaks was revised to reflect the additional MWR information provided by the licensee.

Page 41a

A new page was added to collect the over-run from revised page 41.

Page 42

1. The additional information related to the total number of straight tubes and brazed joints in the F.C.U.s was added.

2. F.U.C. was changed to F.C.U., the correct acronym.

Page 72

1. The description of the item of noncompliance was changed to reflect the fact that the continued leakage and repairs of concern to the NRC investigation team include Fan Cooler Unit Service Water System leaks, both within the units and their supply and return piping.

2. The reference to paragraph 11 closes the loop on information relative to this subject.

Figure 4

The figure was revised to reflect the additional MWR information provided by the licensee.

Figure 6

1. The figure was revised to reflect the additional MWR information provided by the licensee.

2. The information on the total number of F.C.U. Cooling Coil and Motor Heat Exchanger straight tubes and brazed joints is included in the notes to the figure to enable independent evaluation.

1 - Section Chief
2 - Senior Resident Inspectors
1 - Resident Inspector
1 - Reactor Inspector (Quality Assurance)
1 - Reactor Inspector (Non-Destructive Examination)
1 - Reactor Inspector (Corrosion and Metallurgy)
2 - Investigators

Information was gathered through the conduct of interviews, the taking of sworn statements, the inspection of equipment and tours of affected spaces, the review of procedures records, logs, and computer printout, the witnessing of tests, independent computation of volumes and flooding elevations, the construction of charts and information flow diagrams, and the independent non-destructive examination of the Reactor Vessel and Incore Instrument Conduits.

The principle products of this investigation are the transcript of the NRC-Licensee Technical Meeting in White Plains, New York on November 5, 1980, and this investigation report, including a detailed Sequence of Events attached as Enclosure 1 to the report.

Based on the findings of the NRC Investigation Team and that of the licensee, it was determined that additional information relative to the event and the corrective action required to prevent reoccurrence had to be developed and documented. Enclosure 2 documents those reports the licensee has committed to develop and submit to NRC by December 22, 1980. The licensee is further committed to propose new or additional Technical Specifications for the systems contributing to the flooding event, or modified as a result of the event, by February 15, 1981, or plant restart, whichever is later.

4. Licensee Management Activities

a. Event Narrative

(1) Friday - 10/17/80

Upon discovery of the problem with Nuclear Instrument Channel N42, shortly after midnight, operators notified the first shift Senior Watch Supervisor (S.W.S.) (first line supervision) of the condition, who then called the Chief Operations Engineer (C.O.E.) at home and informed him of the problem. It was decided that the S.W.S. would call the Reactor Engineer and request he come to the plant to conduct a flux map. The C.O.E. called the Plant Manager (P.M.) at home and informed him of the developing problem.

Following the determination by the Reactor Engineer and S.W.S. that Channel N42 was failing and should be declared inoperable, the S.W.S. again called the C.O.E., requesting per licensee

9. Reactor Vessel Pit Sump Pumps

a. Description

The pit underneath the reactor vessel extends from about elevation 46' down to about elevation 19'. The initial plant design had no provision for pumping water which somehow managed to collect in the pit. During initial preoperational testing a service water line to an FCU failed, resulting in flooding of this pit. As a result of this occurrence, an Engineering Service Pequest (#238) was initiated on April 14, 1972 to install sump pumps in the pit. These pumps were actually installed during the 1976 refueling outage and pump the reactor vessel pit to the containment sump. The pumps installed are Crane Deming submersible pumps which are designed to operate submerged, not in air. They each have a 100 gallon per minute capacity and a check valve in their discharge. After individual pump check valves the discharge lines tie together, run up to about elevation 52', over to the containment sump and then down to the bottom of the containment sump. No anti-siphon vacuum breaker is included in the line. The motors have a tandem seal design with a moisture detection circuit between the two seals to detect impending or actual motor failure. All controls and the moisture detection alarm lights are inside containment.

(4) Flexible hose failures on the Motor Cooler Heat Exchanger. There is no information available to indicate whether these failures are caused by fatigue or corrosion, however, the most probable cause is fatigue.

c. F.C.U. Status and Maintenance History

The NRC inspector held discussions with site maintenance and corporate engineering personnel to determine if specific failure analysis studies were made on any of the F.C.U. related leaks. No failure analysis had been conducted by the licensee, other than those conducted on cement lined pipe failures, between 1973 and October 1980. (This deficiency is discussed further under QA/QC Program).

Based on information provided the NRC on December 3, 1980, the licensee had performed and documented a failure analysis of five F.C.U. Motor Heat Exchangers in 1973. During the period September 1971 to January 1973, the licensee identified excessive incidents of leakage from these Heat Exchangers. The failure analysis was performed to determine if the cause of these failures was due to excessive cooling water flow rates or other problems. The analysis concluded the failures were due to poor design and/or assembly.

Discussion with the licensee indicates the replacement Motor Heat Exchangers were fabricated and inspected to tighter specifications, which should have eliminated leakage problems in the replacement units.

The maintenance records for the fan coolers were reviewed with the Maintenance Engineer. The design, operation and maintenance of the F.C.U.s was discussed with the Assistant Vice President for Engineering and cognizant engineering personnel selected by him, as indicated in paragraph 11.f. A discussion was held with the Maintenance Engineer following his detailed inspection of the F.C.U.s. Later the NRC inspector conducted a thorough visual inspection of the F.C.U.s, accompanied by the Maintenance Engineer. The report of observations by the Maintenance Engineer of the five F.C.U.s on 10/26/80 indicated 46 previous repair locations (reported in 39 MWR's), and 8-12 current probable leaks. There were 7 currently installed pipe clamps, 8 re-brazed repairs and 18-25 epoxy repairs noted. The 18-25 number results from difficulty identifying general repaired areas as individual or group repairs. A Maintenance Department summary sheet made up from Maintenance Work Request (MWR) records indicates 4 repairs on F.C.U. #21, 4 on F.C.U. #22, 11 on F.C.U. #23, 8 on F.C.U. #24 and 12 on F.C.U. #25. The total of 39 "MWR repairs" includes some multiple repairs conducted under one MWR. The failure rate of the F.C.U.'s Service Water System, due to leaks, is presented on attached Figure 4, in the form of a histogram.

Review of the header/stub tube/heat exchanger tube design by the NRC inspector reaffirmed the licensee's opinion of the difficulty in accomplishing effective repairs to the heat exchanger. The all-brazed design combined with the close spacing of the tubes and relative thickness of tubes and headers (0.035"/0.154-0.237"), makes localized re-brazing almost impossible. (Fix one joint and damage the braze on the adjacent tube joint.) The Maintenance Departme- first attempted re-brazing of the Cu-Ni materials to repair a leak. This was marginally successful along the length of the tubes, but unsuccessful at the header/stub end joints. The only successful leak repair utilized was a "temporary fix" with epoxy resins and fiber glass tape.

Leaks in large diameter cement lined pipes were temporarily repaired with "Adam's Clamps" (rubber gaskets clamped over the leak). Leaks in small diameter pipe sections were repaired with "Adam's Clamps" or by replacement with austentic stainless steel pipe. The Engineering Department indicated that the life of a "temporary fix" was 1 to 3 years.

d. Service Water System

A walk down inspection was made of the observable portions of the service water piping providing cooling water for the F.C.U.s from the 6 Service Water Pumps and their Traveling Screens to the piping penetrations outside of the Vapor Containment. The piping system is cement lined pipe up to the F.C.U. heat exchangers, where the piping is then Cu-Ni. Review of maintenance records and visual observations indicated minimal problems in the large diameter cement lined piping system outside the Vapor Containment. It was reported to the NRC inspector that there have been problems in the piping system associated with localized high velocity (design related) erosion. These problems which occurred early in service life, resulted in installation of stainless steel dutchman sections, in the piping system outside the Vapor Containment.

e. Heat Exchangers

A review was made of maintenance records for the subject heat exchangers. The purpose of the review was to obtain, if possible, a categorization of the failures in these heat exchangers associated with the Service Water cooling system. Equipment failures not related to the Service Water cooling system were not evaluated. Difficulty was encountered in analysis of the maintenance files, due to lack of explicit information on location of failures and repair technique details. Maintenance files were fortunately segregated by Fan Cooler Unit. The results of this cursory analysis by the NRC inspector are shown on attached Figure 6. It should be noted that there are a total of about 6,000 straight tubes and about 18,000 brazed joints in all five F.C.U.s.

f. Meeting With The Licensee Regarding Fan Cooler Unit Heat Exchangers

On October 28, 1980, the NRC Corrosion and Metallurgy Specialist met with members of the licensee's engineering staff. The purpose of the meeting was to discuss the F.C.U. Heat Exchangers (and related parts of Service Water Cooling System) at Indian Point 2. The following information was obtained.

(1) Indian Point 2 (IP2) operation started in 1973-74, so the F.C.U.'s have seen approximately 6 1/2 years (interrupted) service.

(2) In February 1979, corporate engineering started to review the repair procedures utilized, i.e., the EPI SEAL tube plugging procedure.

quality levels and evaluation of material useage; and, 10 CFR 50.59(b) which requires that safety evaluations be performed for changes to the facility and those records retained.

The inspectors also identified that the Station Nuclear Safety Committee did not review, as required by TS 6.5.1.6, the modifications made to Service Water Piping and Cooling Coils, associated with the Fan Cooler Units, between 1973 and October 21, 1980. These modifications were designated "temporary repairs" and were made to leaking components, using epoxy type sealants and pipe clamps.

The above constitutes an item of noncompliance (50-247/80-19-44).

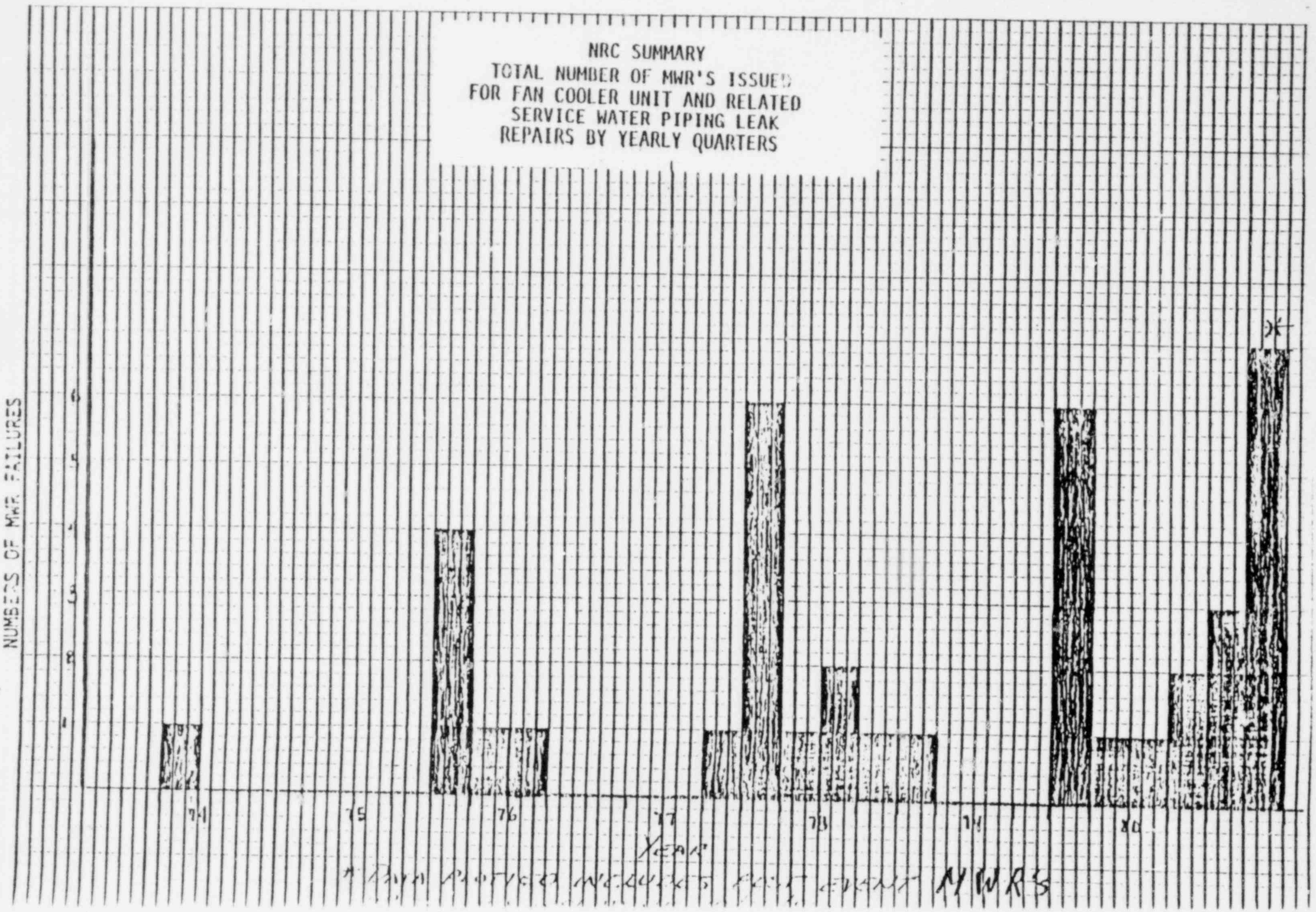
(2) Despite continued Fan Cooler Unit Service Water System leakage and many repairs of these leaks between 1973 and October, 1980, the licensee had not made any determination of the causes of the leakage problem or recorded such action; nor had the evaluation of the causes for such leakage, which had been initiated, ever been completed. Additional details are included in paragraph 11.

This is contrary to: 10 CFR 50, Appendix B, and Criterion II, which requires programatic control over such activities; and FSAR Volume A, Attachment A-2, which commits to ANSI N18.7-1976, which in turn requires that the causes of malfunctions (i.e., leaks) be promptly determined, evaluated and recorded.

This is an item of noncompliance (50-247/80-19-45).

(3) Technical Specification (TS) 6.8.1 commits to ANSI N18.7-1972, Paragraph 5.1.6.1 of which requires that maintenance and modifications that may affect the functioning of safety related systems be preplanned and performed in accordance with written procedures appropriate to the circumstances.

Contrary to this requirement, site administrative procedures were not established, implemented and maintained to provide guidance as to: (1) when written and approved procedures were required for maintenance activities; and, (2) when maintenance activities constitute a modification; both of which require review and concurrence by the Station Nuclear Safety Committee. The inspector was aware of a memorandum that discussed modifications, which had been issued (March 14, 1977) by the Director of Quality Assurance. The inspector noted that these instructions did not appear to have been implemented in that: (1) there were no corresponding site or maintenance department instructions; (2) past and present Maintenance Engineers were unaware of it; and, (3) if the instructions had been implemented, the epoxy repairs discussed elsewhere in this report would have been considered as modifications, which they (the epoxy repairs) were not.


NRC SUMMARY
TOTAL NUMBER OF MWR'S ISSUED
FOR FAN COOLER UNIT AND RELATED
SERVICE WATER PIPING LEAK
REPAIRS BY YEARLY QUARTERS
NUMBERS OF MWR FAILURES
1
2
3
4
5
6
74
75
76
77
78
79
80
Year
*

FAN COOLER UNIT/

SERVICE WATER LEAK

HUR CATEGORIZATION

FAN COOLER UNIT	STUB TUBE BRAZING FAILURES	TUBE FAILURES	FLEX HOSE FAILURES	CEMENT LINED PIPE FAILURES	PREVIOUS REPAIR FAILURES	FIELD REPLACEMENT S.S. WELD FAILURES	BRAZED JOINTS OTHER THAN STUB TUBE FAILURES	TOTAL CORROSION AND JOINING FAILURES
21	2	1		1				4
22	1		2	1				4
23	1	2		4		2	2	11
21	1			3	3		1	8
25	3	2(1)	1	3	3			12
TOTAL	8	5	3	12	6	2	3	39

NOTES (1) INCLUDES 5 TUBE FAILURES IN ONE TUBE AS ONE (1) FAILURE

(2) THERE ARE A TOTAL OF ABOUT 6000 SANDVIK TUBES AND ABOUT 18,000 BRAZED JOINTS IN ALL FIVE FAN COOLER UNITS

FIGURE [illegible]

APR 2 1981

MEMORANDUM FOR: Leonard Bickwit, OGC

FROM: Victor Stello, Jr., Director
Office of Inspection and Enforcement

SUBJECT: CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
(INDIAN POINT NUCLEAR POWER STATION, UNIT 2)
REFERRAL TO DEPARTMENT OF JUSTICE FOR COLLECTION OF CIVIL PENALTIES

On December 11, 1980, I served upon Consolidated Edison Company of New York a Notice of Violation and Proposed Imposition of Civil Penalty in the amount of two hundred ten thousand dollars. The proposed penalty action was based on the findings resulting from an IE investigation conducted on October 22, 1980 through November 21, 1980, at the Indian Point Nuclear Power Station, Unit 2. The investigative findings related to ten alleged violations of Commission requirements which were associated with the flooding of the Indian Point Unit 2 reactor containment on October 17, 1980, and involved (1) failure to report a significant occurrence, (2) failure in the management control system designed to prevent or mitigate a serious safety event, and (3) inadequate implementation of the Shift Technical Advisor's function. This penalty was proposed in accordance with the Interim Enforcement Policy as published in the Federal Register October 7, 1980 (45 FR 66754). The Commission was briefed on the proposed penalty on December 10, 1980.

By letters dated January 5 and February 11, 1981, Consolidated Edison responded to the December 11, 1980 Notice, contending that there was no failure in their management control system and providing additional details about the alleged violations and the flooding incident in general.

After evaluating Consolidated Edison's responses, I concluded that there was no basis for mitigation of the proposed penalty and on March 2, 1981, served upon the Company an Order Imposing Civil Monetary Penalties in the amount of two hundred ten thousand dollars. The Order provided that the company could either pay the total amount of the penalties within twenty-five days of the date of the Order or request a hearing on the matter within the said twenty-five day period. The Order further provided that in the event a hearing was not requested, the Order was to become effective without further proceedings, and that if payment had not been received, the matter could be referred to the Attorney General for collection.

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PDR

In a response dated March 26, 1981, Consolidated Edison indicated its intent to not seek an administrative hearing with respect to the imposed penalty, but rather to defend its actions in any collection suit the Commission might wish to undertake. Accordingly, please refer this matter to the Department of Justice for collection of the imposed penalty in accordance with 10 CFR 2.205(h) and section 234(c) of the Atomic Energy Act of 1954, as amended.

Please keep me informed of the progress in this matter and my office will provide assistance as necessary.

R C DeYoung, for
Victor Stello, Jr.
Director
Office of Inspection and Enforcement

Enclosures:
A. Notice of Violation and Proposed Imposition of Civil Penalty, December 11, 1980.
B. Consolidated Edison's Response to Notice of Violation and Proposed Imposition of Civil Penalty, January 5, 1981 (as Supplemented February 11, 1981).
C. Order Imposing Civil Monetary Penalties, March 2, 1981.
D. Letter to Victor Stello from Consolidated Edison Co. of New York, Inc., March 26, 1981.
E. Inspection Report 50-247/80-19.