NUREG-0090
Vol. 7, No. 2

Report to Congress on Abnormal Occurrences

April - June 1984

U.S. Nuclear Regulatory Commission
Office for Analysis and Evaluation of Operational Data

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Previous Reports in Series

NUREG 75/090, January-June 1975, published October 1975

NUREG-0090-1, July-September 1975, published March 1976

NUREG-0090-2, October-December 1975, published March 1976

NUREG-0090-3, January-March 1976, published July 1976

NUREG-0090-4, April-June 1976, published March 1977

NUREG-0090-5, July-September 1976, published March 1977

NUREG-0090-6, October-December 1976, published June 1977

NUREG-0090-7, January-March 1977, published June 1977

NUREG-0090-8, April-June 1977, published September 1977

NUREG-0090-9, July-September 1977, published November 1977

NUREG-0090-10, October-December 1977, published March 1978

NUREG-0090, Vol.1, No.1, January-March 1978, published June 1978

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NUREG-0090, Vol.2, No.1, January-March 1979, published July 1979

NUREG-0090, Vol.2, No.2, April-June 1979, published November 1979

NUREG-0090, Vol.2, No.3, July-September 1979, published February 1980

NUREG-0090, Vol.2, No.4, October-December 1979, published April 1980

NUREG-0090, Vol.3, No.1, January-March 1980, published September 1980

NUREG-0090, Vol.3, No.2, April-June 1980, published November 1980

NUREG-0090, Vol.3, No.3, July-September 1980, published February 1981

NUREG-0090, Vol.3, No.4, October-December 1980, published May 1981

NUREG-0090, Vol.4, No.1, January-March 1981, published July 1981

NUREG-0090, Vol.4, No.2, April-June 1981, published October 1981

NUREG-0090, Vol.4, No.3, July-September 1981, published January 1982

NUREG-0090, Vol.4, No.4, October-December 1981, published May 1982

NUREG-0090, Vol.5, No.1, January-March 1982 published August 1982

NUREG-0090, Vol.5, No.2, April-June 1982, published December 1982

NUREG-0090, Vol.5, No.3, July-September 1982, published January 1983

NUREG-0090, Vol.5, No.4, October-December 1982, published May 1983

NUREG-0090, Vol.6, No.1, January-March 1983, published September 1983

NUREG-0090, Vol.6, No.2, April-June 1983, published November 1983

NUREG-0090, Vol.6, No.3, July-September 1983, published April 1984

NUREG-0090, Vol.6, No.4, October-December 1983, published May 1984

NUREG-0090, Vol.7, No.1, January-March 1984, published July 1984

ABSTRACT

Section 208 of the Energy Reorganization Act of 1974 identifies an abnormal occurrence as an unscheduled incident or event which the Nuclear Regulatory Commission determines to be significant from the standpoint of public health or safety and requires a quarterly report of such events to be made to Congress. This report covers the period from April 1 to June 30, 1984.

The report states that for this report period, there was one abnormal occurrence at the nuclear power plants licensed to operate; the event involved an inoperable containment spray system. There was one abnormal occurrence at the other NRC licensees; the event involved a therapeutic medical misadministration. There were no abnormal occurrences reported by the Agreement States.

The report also contains information updating some previously reported abnormal occurrences.

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PREFACE

INTRODUCTION

The Nuclear Regulatory Commission reports to the Congress each quarter under provisions of Section 208 of the Energy Reorganization Act of 1974 on any abnormal occurrences involving facilities and activities regulated by the NRC. An abnormal occurrence is defined in Section 208 as an unscheduled incident or event which the Commission determines is significant from the standpoint of public health or safety.

Events are currently identified as abnormal occurrences for this report by the NRC using the criteria delineated in Appendix A. These criteria were promulgated in an NRC policy statement which was published in the Federal Register on February 24, 1977 (Vol. 42, No. 37, pages 10950-10952). In order to provide wide dissemination of information to the public, a Federal Register notice is issued on each abnormal occurrence with copies distributed to the NRC Public Document Room and all local public document rooms. At a minimum, each such notice contains the date and place of the occurrence and describes its nature and probable consequences.

The NRC has reviewed Licensee Event Reports, licensing and enforcement actions (e.g., notices of violations, civil penalties, license modifications, etc.), generic issues, significant inventory differences involving special nuclear material, and other categories of information available to the NRC. The NRC has determined that only those events, including those submitted by the Agreement States, described in this report meet the criteria for abnormal occurrence reporting. This report covers the period from April 1 to June 30, 1984.

Information reported on each event includes: date and place; nature and probable consequences; cause or causes; and actions taken to prevent recurrence.

THE REGULATORY SYSTEM

The system of licensing and regulation by which NRC carries out its responsibilities is implemented through rules and regulations in Title 10 of the Code of Federal Regulations. To accomplish its objectives, NRC regularly conducts licensing proceedings, inspection and enforcement activities, evaluation of operating experience and confirmatory research, while maintaining programs for establishing standards and issuing technical reviews and studies. The NRC's role in regulating represents a complete cycle, with the NRC establishing standards and rules; issuing licenses and permits; inspecting for compliance; enforcing license requirements; and carrying on continuing evaluations, studies and research projects to improve both the regulatory process and the protection of the public health and safety. Public participation is an element of the regulatory process.

In the licensing and regulation of nuclear power plants, the NRC follows the philosophy that the health and safety of the public are best assured through the establishment of multiple levels of protection. These multiple levels can be achieved and maintained through regulations which specify requirements which will assure the safe use of nuclear materials. The regulations include design and quality assurance criteria appropriate for the various activities licensed by NRC. An inspection and enforcement program helps assure compliance with the regulations.

Most NRC licensee employees who work with or in the vicinity of radioactive materials are required to utilize personnel monitoring devices such as film badges or TLD (thermoluminescent dosimeter) badges. These badges are processed periodically and the exposure results normally serve as the official and legal record of the extent of personnel exposure to radiation during the period the badge was worn. If an individual's past exposure history is known and has been sufficiently low, NRC regulations permit an individual in a restricted area to receive up to three rems of whole body exposure in a calendar quarter. Higher values are permitted to the extremities or skin of the whole body. For unrestricted areas, permissible levels of radiation are considerably smaller. Permissible doses for restricted areas and unrestricted areas are stated in 10 CFR Part 20. In any case, the NRC's policy is to maintain radiation exposures to levels as low as reasonably achievable.

REPORTABLE OCCURRENCES

Actual operating experience is an essential input to the regulatory process for assuring that licensed activities are conducted safely. Reporting requirements exist which require that licensees report certain incidents or events to the NRC. This reporting helps to identify deficiencies early and to assure that corrective actions are taken to prevent recurrence.

For nuclear power plants, dedicated groups have been formed both by the NRC and by the nuclear power industry for the detailed review of operating experience to help identify safety concerns early, to improve dissemination of such information, and to feed back the experience into licensing, regulations, and operations.

In addition, the NRC and the nuclear power industry have ongoing efforts to improve the operational data system which include not only the type, and quality, of reports required to be submitted, but also the methods used to analyze the data. Two primary sources of operational data are reports submitted by the licensees under the Licensee Event Report (LER) system, and under the Nuclear Plant Reliability Data (NPRD) system. The former system is under the control of the NRC while the latter system is a voluntary, industry-supported system operated by the Institute of Nuclear Power Operations (INPO), a nuclear utility organization.

Some form of LER reporting system has been in existence since the first nuclear power plant was licensed. Reporting requirements were delineated in the Code of Federal Regulations (10 CFR), in the licensees' technical specifications, and/or in license provisions. In order to more effectively collect, collate, store, retrieve, and evaluate the information concerning reportable events, the Atomic Energy Commission (the predecessor of the NRC) established in 1973 a computer-based data file, with data extracted from licensee reports dating from 1969. Periodically, changes were made to improve both the effectiveness of data processing and the quality of reports required to be submitted by the licensees.

Effective January 1, 1984, major changes were made to the requirements to report to the NRC. A revised Licensee Event Report System (10 CFR § 50.73) was established by Commission rulemaking which modified and codified the former LER system. The purpose was to standardize the reporting requirements for all nuclear power plant licensees and eliminate reporting of events which were of low individual significance, while requiring more thorough documentation and analyses by the licensees of any events required to be reported. All such reports are to be submitted within 30 days of discovery. The revised system also permits licensees to use the LER procedures for various other reports required under specific sections of 10 CFR Part 20 and Part 50. The amendment to the Commission's regulations was published in the Federal Register (48 FR 33850) on July 26, 1983, and is described in NUREG-1022, "Licensee Event Report System," and Supplement 1 to NUREG-1022.

Also effective January 1, 1984, the NRC amended its immediate notification requirements of significant events at operating nuclear power reactors (10 CFR § 50.72). This was published in the Federal Register (48 FR 39039) on August 29, 1983, with corrections (48 FR 40882) published on September 12, 1983. Among the changes made were the use of terminology, phrasing, and reporting thresholds that are similar to those of 10 CFR § 50.73. Therefore, most events reported under 10 CFR § 50.72 will also require an in-depth follow-up report under 10 CFR § 50.73.

The NPRD system is a voluntary program for the reporting of reliability data by nuclear power plant licensees. Both engineering and failure data are to be submitted by licensees for specified plant components and systems. In the past, industry participation in the NPRD system was limited and, as a result, the Commission considered that it may be necessary to make participation mandatory in order to make the system a viable tool in analyzing operating experience. However, on June 8, 1981, INPO announced that because of its role as an active user of NPRD system data, it would assume responsibility for management and funding of the NPRD system. INPO reports that significant improvements in licensee participation are being made. The Commission considers the NPRD system to be a vital adjunct to the LER system for the collection, review, and feedback of operational experience; therefore, the Commission periodically monitors the progress made on improving the NPRD system.

Information concerning reportable occurrences at facilities licensed or otherwise regulated by the NRC is routinely disseminated by the NRC to the nuclear industry, the public, and other interested groups as these events occur. Dissemination includes special notifications to licensees and other affected or interested groups, and public announcements. In addition, information on reportable events is routinely sent to the NRC's more than 100 local public document rooms throughout the United States and to the NRC Public Document Room in Washington, D.C.

The Congress is routinely kept informed of reportable events occurring at licensed facilities.

AGREEMENT STATES

Section 274 of the Atomic Energy Act, as amended, authorizes the Commission to enter into agreements with States whereby the Commission relinquishes and the States assume regulatory authority over byproduct, source and special nuclear materials (in quantities not capable of sustaining a chain reaction). Comparable and compatible programs are the basis for agreements.

Presently, information on reportable occurrences in Agreement State licensed activities is publicly available at the State level. Certain information is also provided to the NRC under exchange of information provisions in the agreements. NRC prepares a semiannual summary of this and other information in a document entitled, "Licensing Statistics and Other Data," which is publicly available.

In early 1977, the Commission determined that abnormal occurrences happening at facilities of Agreement State licensees should be included in the quarterly report to Congress. The abnormal occurrence criteria included in Appendix A is applied uniformly to events at NRC and Agreement State licensee facilities. Procedures have been developed and implemented and abnormal occurrences reported by the Agreement States to the NRC are included in these quarterly reports to Congress.

FOREIGN INFORMATION

The NRC participates in an exchange of information with various foreign governments which have nuclear facilities. This foreign information is reviewed and considered in the NRC's assessment of operating experience and in its research and regulatory activities. Reference to foreign information may occasionally be made in these quarterly abnormal occurrence reports to Congress; however, only domestic abnormal occurrences are reported.

REPORT TO CONGRESS ON ABNORMAL OCCURRENCES

APRIL-JUNE 1984

NUCLEAR POWER PLANTS

The NRC is reviewing events reported at the nuclear power plants licensed to operate during the second calendar quarter of 1984. As of the date of this report, the NRC had determined that the following was an abnormal occurrence.

84-6 Inoperable Containment Spray System

Preliminary information pertaining to this event was reported in the Federal Register (Ref. 1). Appendix A (see general criterion 2) of the report notes that major degradation of essential safety-related equipment can be considered an abnormal occurrence. In addition, Example 3 under "For Commercial Nuclear Power Plants" of Appendix A notes that loss of plant capability to perform essential safety functions such that a potential release of radioactivity in excess of 10 CFR Part 100 guidelines could result from a postulated transient or accident (e.g., loss of emergency core cooling system, loss of control rod system) can be considered an abnormal occurrence.

Date and Place - On March 17, 1984, Southern California Edison Company (the licensee) discovered that both containment spray pump manual discharge isolation valves were locked shut, thus rendering both independent containment spray systems inoperable at the San Onofre Nuclear Generating Station, Unit 3. It was found that the condition had existed for about 13 days, during which the plant had operated at power levels up to full power. San Onofre Unit 3, which utilizes a Combustion Engineering-designed pressurized water reactor, is located in San Diego County, California.

Nature and Probable Consequences - The containment heat removal system (CHRS) at San Onofre Unit 3 is an engineered safety features system designed to remove heat from the containment atmosphere in the event of a loss of coolant accident (LOCA) or main steam line break (MSLB) inside containment. Removal of heat reduces the containment pressure and temperature, which reduces the leakage of airborne activity from the containment. The CHRS includes the containment spray system (CSS) and the containment emergency fan cooler system. The CSS also contains a chemical additive (sodium hydroxide) which reduces the concentration of radioactive iodine in the containment atmosphere following a postulated accident.

The CSS and the containment emergency fan cooler system constitute two 100% capacity systems in that each is designed to independently remove heat from the containment atmosphere, following a postulated accident inside containment, to maintain the containment atmosphere pressure below the containment design pressure of 60 psig. Each of the two trains of the CSS constitutes a 50% capacity system for required heat removal rate and a 100% capacity system for iodine reduction. Each of the two trains (each containing two fan coolers) of the containment emergency fan cooler system constitutes a 50% capacity system for required heat removal rate.

On March 17, 1984, with the unit in Mode 1 at approximately 100% power, manual isolation valves MU012 and MU014 were observed by a plant operator to be in the closed position. These valves are on the discharge side of the containment spray pumps and are located outside of containment. With both valves closed, both trains of the CSS were inoperable for automatic actuation. Investigation showed the following details associated with the event.

On February 27, 1984, the unit entered Mode 4 from Mode 5. Procedure SO23-3-2.9, "Containment Spray/Iodine Removal System Operation," Checklist 5.1 was performed to align the CSS in preparation for Mode 3 operation. MU012 and MU014 were verified to be in the locked open position. On February 28, 1984, preparations were being made to return to Mode 5 in order to repair a high pressure safety injection (HPSI) valve. Valves MU012 and MU014 were closed in accordance with procedures in order to return to shutdown cooling operation. On March 2, 1984 following repair of the HPSI valve, preparations were being made to return to Mode 3. The Control Room Supervisor developed a partial valve alignment checklist from Checklist 5.1 of Procedure SO23-3.2.9 to realign the CSS. Since the outage did not involve work on the CSS and the entire Checklist 5.1 had been performed four days earlier on February 28, 1984, the plant personnel agreed that a complete alignment checklist was unnecessary. CSS valves MU012 and MU014 were erroneously omitted from the partial checklist.

There was a second opportunity on March 2, 1984 in which the licensee could have detected the valving error, but failed to do so. On March 2, 1984, a containment spray pump was operated to flush the spray header and the operator failed to verify flow from the flow-rate-meter in the control room.

At 9:55 a.m. on March 4, 1984, the unit entered Mode 3 with both trains of the CSS inoperable in violation of the technical specifications. The plant operated in Modes 3, 2, and 1 in this manner until the condition was corrected at 2:00 p.m. on March 17, 1984, a period of about 13 days.

During this period, another violation occurred which further degraded the CHRS. From about 4:20 a.m. on March 15, 1984, to about 5:35 p.m. on March 16, 1984, one of the two diesel generators was removed from service (placed in maintenance lockout); thus, the emergency power source (had there been a total loss of offsite power) for the associated train of the containment emergency fan cooler system was inoperable. This violation occurred since the licensee was unaware that the CSS was inoperable at the time.

Although there was no actual demand for the containment cooling systems to perform their accident mitigating functions during the 13 day period, substantial degradation of the capability of the systems to mitigate the consequences of a postulated loss of reactor coolant accident did exist. During the time in question, automatic actuation of the CSS would not have been possible. However, there are indications in the control room which could inform the reactor operators that spray injection was not taking place. Upon recognizing the situation, manual actuation of the CSS could have been made.

Although the reactor operators could be expected to take timely actions, the NRC staff has performed bounding calculations to predict worse case conditions in order to determine whether the containment design pressure or the post-accident off-site dose limitations would be exceeded after a design basis accident. For the staff's calculations, it was assumed that one diesel generator would be out of service which would preclude operation of two out of four containment fan cooler units. This assumption was made because during part of the time in question, one of the diesel generators was taken out of service for maintenance as discussed above. The NRC findings were:

1. The containment design pressure (60 psig) would have been exceeded if a design basis LOCA had occurred during the period of degraded containment cooling. The licensee calculated a peak pressure of 65 psig whereas the NRC analysis results in 62 psig. As noted by the licensee, however, the containment has been successfully tested to a pressure of 69 psig during preoperational testing. Therefore, containment integrity would not have been breached by the LOCA, if it had occurred during the time when the containment sprays and one diesel generator train were disabled.

2. Given that containment integrity would have been maintained, the licensee calculated a worst case dose at the exclusion area boundary of 240 rems to the thyroid, assuming a one hour delay in containment spray operation. The NRC analysis of this case resulted in 420 rems (thyroid), which is above the 10 CFR Part 100 limit of 300 rems. The difference in the two dose values appears to be the result of the use by the NRC of meteorological analysis and model consistent with those used in the NRC's Safety Evaluation Report, NUREG-0712, while the licensee used the meteorological evaluation from its final safety analysis report (FSAR).

Cause or Causes - The apparent underlying causes of the event were: (1) inadequate review and approval of changes made to a previously established valve alignment check list and (2) the existence of an administrative procedure (SO23-0-35), promulgated by management, which allowed such changes to be made without adequate review and approvals.

At San Onofre, administrative procedures provide authorization for a senior reactor operator (SRO) Supervisor to designate only a portion of a checklist for use when circumstances warrant. This authorization was included to avoid errors resulting from development of special purpose checklists when conducting retests following correction of component failures within lengthy surveillance procedures, for example. Other objectives of this provision included ALARA (as low as reasonably achievable) exposure considerations, where complete system alignment checklists include vents and drains in high radiation areas which were not affected by a particular evolution, and secondary plant equipment alignments which usually involve only a portion of any one system checklist. This authorization was not intended for use in establishing a partial checklist of main process valves when performing a system evolution such as leaving shutdown cooling alignment and establishing CSS operability. However, this intent was not clear. In this case, the authorization was used to, in effect, revise the procedure intended to establish CSS operability contrary to the intent.

The Control Room Supervisor (an SRO) did not recognize that the containment spray pump manual discharge isolation valves were closed when entering the shutdown cooling alignment. Therefore, in designating the subset of CSS valves to be repositioned and verified upon leaving the shutdown cooling alignment, valves MU012 and MU014 were omitted and remained closed until identified on March 17. No Piping and Instrumentation Diagram (P&ID) was provided to explicitly show the valve alignment for shutdown cooling. Also, no partial checklist was provided for the subset of CSS valves required to be repositioned when leaving shutdown cooling. Accordingly, there was no effective procedural means to ensure MU012 and MU014 would be opened, short of reperforming the entire CSS valve alignment checklist. As described in the sequence of events above, since the entire checklist had been performed on February 28, 1984, the Control Room Supervisor and the Shift Superintendent considered that it did not need to be reperformed.

Actions Taken to Prevent Recurrence

Licensee - The licensee has revised written procedures to ensure the proper alignment of valves prior to entering a mode of operation for which the system is required to be operable. Steps have also been taken by the licensee to ensure more effective controls over the preparation of and changes to operating procedures. The licensee's training program is being revised to provide additional emphasis on operator recognition of proper system alignments during various plant evolutions.

NRC - An examination of the circumstances associated with the event was included in an inspection performed at the licensee during the period of March 17 through March 29, 1984. The report of the inspection was sent to the licensee on April 5, 1984 (Ref. 2). An enforcement conference was held between NRC Region V and licensee personnel on May 7, 1984.

On May 16, 1984, NRC Region V forwarded to the licensee a notice of violations and proposed imposition of civil penalties in the amount of $250,000 (Ref. 3). The forwarding letter expressed the NRC's serious concern that the event resulted in a significant degradation in the engineered safety features of the facility, and that inadequate management controls contributed substantially as an underlying cause. The letter further noted that several other enforcement actions since January 1983 pertaining to the licensee's San Onofre Units 2 and 3 facilities indicate that management problems have not been adequately corrected.

Based on the licensee's prompt and extensive corrective actions, the NRC reduced the civil penalty to $125,000 on September 24, 1984 (Ref. 4).

During the past several years, there have been several events at various nuclear power plants involving degradation of containment spray systems. On May 25, 1984, the NRC issued Inspection and Enforcement Information Notice No. 84-39 ("Inadvertent Isolation of Containment Spray Systems") to all facilities holding an operating license or construction permit (Ref. 5). This may help to reduce the frequency of these types of events by heightening the industry's awareness of the potential for such events and the circumstances associated with their occurrence.

There have been previously reported abnormal occurrences involving similar events. Abnormal Occurrence 82-7 in NUREG-0090, Vol. 5, No. 4 ("Report to Congress on Abnormal Occurrences: October - December 1982") described a similar event at Farley Unit 2 which was discovered on October 28, 1982. Abnormal Occurrence 84-1 in NUREG-0900, Vol. 7, No. 1 ("Report to Congress on Abnormal Occurrences: January - March 1984") described a similar event at Indian Point Unit 2 which was discovered on November 29, 1983.

This incident is closed for purposes of this report.

FUEL CYCLE FACILITIES

(Other than Nuclear Power Plants)

The NRC is reviewing events reported by these licensees during the second calendar quarter of 1984. As of the date of this report, the NRC had not determined that any events were abnormal occurrences.

OTHER NRC LICENSEES

(Industrial Radiographers, Medical Institutions, Industrial Users, etc.)

There are currently more than 8,000 NRC nuclear material licenses in effect in the United States, principally for use of radioisotopes in the medical, industrial, and academic fields. Incidents were reported in this category from licensees such as radiographers, medical institutions, and byproduct material users.

The NRC is reviewing events reported by these licensees during the second calendar quarter of 1984. As of the date of this report, the NRC had determined that the following was an abnormal occurrence.

84-7 Therapeutic Medical Misadministration

The following information pertaining to this event is also being reported concurrently in the Federal Register. Appendix A (see the general criteria) of this report notes that a major reduction in the degree of protection of the public health or safety can be considered an abnormal occurrence.

Date and Place - Between April 11, 1984, and April 20, 1984, a patient at the St. John's Medical Center, Anderson, Indiana, received a 3,200 rad therapeutic radiation exposure to the rear chest wall instead of the intended 2,000 rad exposure.

Nature and Probable Consequences - A patient, following surgery for removal of a lung, was scheduled for radiation therapy using the hospital's cobalt-60 teletherapy device. The prescription called for five treatments of approximately 400 rads each for a total of 2,000 rads.

Because of an error in the computer calculations in the treatment plan for the patient, the patient received two treatments of 400 rads and three of 800 rads for a total exposure of 3,200 rads.

The licensee stated in its report on April 30, 1984, that there were no significant effects evident at the time; however, the patient would have a higher risk of radiation pneumonitis of the remainder of the right lung.

Cause or Causes - The licensee utilizes the services of another hospital to provide computerized treatment planning for radiation therapy. In this instance, the original computer program was not considered accurate for the St. John's Medical Center teletherapy unit and a different computer program was obtained.

In preparing the treatment plan, however, data for the original program was used, resulting in an error in the treatment plan which led to the excessive exposure. The error was discovered in a review by the attending physician after the treatments were completed.

Actions Taken to Prevent Recurrence

Licensee - The erroneous program data has been removed from the computer used in preparing the treatment plans. The hospital providing the treatment planning intends to verify all treatment plans by using a hand-calculated check before the plans are implemented. Expected radiation exposures will also be compared to actual radiation measurements before being used in the treatment plans.

NRC - The NRC has evaluated the measures taken by the licensee and by the hospital providing the treatment plans and considers them to be appropriate. The licensee's radiation therapy program was reviewed during a July 24, 1984, inspection, and it was concluded that appropriate corrective actions have been taken by the licensee.

An NRC medical consultant agreed with the licensee's statement regarding the effects on the patient.

This incident is closed for purposes of this report.

AGREEMENT STATE LICENSEES

Procedures have been developed for the Agreement States to screen unscheduled incidents or events using the same criteria as the NRC (see Appendix A) and report the events to the NRC for inclusion in this report. During the second calendar quarter of 1984, the Agreement States reported no abnormal occurrences to the NRC.

REFERENCES

1. U.S. Nuclear Regulatory Commission, "Abnormal Occurrence: Inoperable Containment Spray System," Federal Register, Vol. 49, No. 177, September 11, 1984, 35703-35705.

2. Letter from T. W. Bishop, Chief, Reactor Projects Branch No. 2, NRC Region V, to Kenneth P. Baskin, Vice President, Nuclear Engineering, Safety and Licensing, Southern California Edison Company, forwarding Inspection Report No. 50-362/84-09, Docket No. 50-362, April 5, 1984.*

3. Letter from J. B. Martin, Regional Administrator, NRC Region V, to D. J. Fogarty, Executive Vice President, Southern California Edison Company, forwarding Notice of Violation and Proposed Imposition of Civil Penalty, Docket No. 50-362, May 16, 1984.*

4. Letter from R. C. DeYoung, Director, NRC Office of Inspection and Enforcement, to D. J. Fogarty, Executive Vice President, Southern California Edison Company, forwarding an Order Imposing Civil Monetary Penalty and an evaluation of the licensee's response, Docket No. 50-362, September 24, 1984.*

5. U.S. Nuclear Regulatory Commission, Inspection and Enforcement Information Notice No. 84-39, "Inadvertent Isolation of Containment Spray Systems," May 25, 1984.*

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*Available in NRC Public Document Room, 1717 H Street, NW, Washington, DC 20555 for inspection and copying (for a fee).

APPENDIX A

ABNORMAL OCCURRENCE CRITERIA

The following criteria for this report's abnormal occurrence determinations were set forth in an NRC policy statement published in the Federal Register on February 24, 1977 (Vol. 43, No. 37, pages 10950-10952).

Events involving a major reduction in the degree of protection of the public health or safety. Such an event would involve a moderate or more severe impact on the public health or safety and could include but need not be limited to:

1. Moderate exposure to, or release of, radioactive material licensed by or otherwise regulated by the Commission;

2. Major degradation of essential safety-related equipment; or

3. Major deficiencies in design, construction, use of, or management controls for licensed facilities or material.

Examples of the types of events that are evaluated in detail using these criteria are:

For All Licensees

1. Exposure of the whole body of any individual to 25 rems or more of radiation; exposure of the skin of the whole body of any individual to 150 rems or more of radiation; or exposure of the feet, ankles, hands or forearms of any individual to 375 rems or more of radiation (10 CFR §20.403(a)(1)), or equivalent exposures from internal sources.

2. An exposure to an individual in an unrestricted area such that the whole-body dose received exceeds 0.5 rem in one calendar year (10 CFR §20.105(a)).

3. The release of radioactive material to an unrestricted area in concentrations which, if averaged over a period of 24 hours, exceed 500 times the regulatory limit of Appendix B, Table II, 10 CFR Part 20 (10 CFR §20.403(b)(2)).

4. Radiation or contamination levels in excess of design values on packages, or loss of confinement of radioactive material such as (a) a radiation dose rate of 1,000 mrem per hour three feet from the surface of a package containing the radioactive material, or (b) release of radioactive material from a package in amounts greater than the regulatory limit.

5. Any loss of licensed material in such quantities and under such circumstances that substantial hazard may result to persons in unrestricted areas.

6. A substantiated case of actual or attempted theft or diversion of licensed material or sabotage of a facility.

7. Any substantiated loss of special nuclear material or any substantiated inventory discrepancy which is judged to be significant relative to normally expected performance and which is judged to be caused by theft or diversion or by substantial breakdown of the accountability system.

8. Any substantial breakdown of physical security or material control (i.e., access control, containment, or accountability systems) that significantly weakened the protection against theft, diversion or sabotage.

9. An accidental criticality (10 CFR §70.52(a)).

10. A major deficiency in design, construction or operation having safety implications requiring immediate remedial action.

11. Serious deficiency in management or procedural controls in major areas.

12. Series of events (where individual events are not of major importance), recurring incidents, and incidents with implications for similar facilities (generic incidents), which create major safety concern.

For Commercial Nuclear Power Plants

1. Exceeding a safety limit of license technical specifications (10 CFR §50.36(c)).

2. Major degradation of fuel integrity, primary coolant pressure boundary, or primary containment boundary.

3. Loss of plant capability to perform essential safety functions such that a potential release of radioactivity in excess of 10 CFR Part 100 guidelines could result from a postulated transient or accident (e.g., loss of emergency core cooling system, loss of control rod system).

4. Discovery of a major condition not specifically considered in the safety analysis report (SAR) or technical specifications that requires immediate remedial action.

5. Personnel error or procedural deficiencies which result in loss of plant capability to perform essential safety functions such that a potential release of radioactivity in excess of 10 CFR Part 100 guidelines could result from a postulated transient or accident (e.g., loss of emergency core cooling system, loss of control rod system).

For Fuel Cycle Licenses

1. A safety limit of license technical specifications is exceeded and a plant shutdown is required (10 CFR §50.36(c)).

2. A major condition not specifically considered in the safety analysis report or technical specifications that requires immediate remedial action.

3. An event which seriously compromised the ability of a confinement system to perform its designated function.

APPENDIX B

UPDATE OF PREVIOUSLY REPORTED ABNORMAL OCCURRENCES

During the April through June, 1984 period, the NRC, NRC licensees, Agreement States, Agreement State licensees, and other involved parties, such as reactor vendors and architects and engineers, continued with the implementation of actions necessary to prevent recurrence of previously reported abnormal occurrences. The referenced Congressional abnormal occurrence reports below provide the initial and any updating information on the abnormal occurrences discussed. Those occurrences not now considered closed will be discussed in subsequent reports in the series.

NUCLEAR POWER PLANTS

76-11 Steam Generator Problems

This abnormal occurrence was originally reported in NUREG-0090-5, "Report to Congress on Abnormal Occurrences: July - September 1976," under the title of "Steam Generator Tube Integrity," and updated in subsequent reports in the series, i.e., NUREG-0090-8; Vol. 1, No. 4; Vol. 2, No. 3; Vol. 2, No. 4; Vol. 3, No. 1; Vol. 3, No. 2; Vol. 3, No. 4; Vol. 4, No. 1; and Vol.5, No. 2. In the latter report, the title was changed to "Steam Generator Problems" since the scope of the reporting was expanded to include more than steam generator tube problems. The item is further updated as follows.

The NRC has periodically issued reports of steam generator operating experience in the various pressurized water reactor (PWR) plants. In January 1979, NUREG-0523 ("Summary of Operating Experience with Recirculating Steam Generators") was published (Ref. B-1). This report discussed the operating problems associated with Westinghouse and Combustion Engineering steam generators. In March 1980, NUREG-0571 ("Summary of Tube Integrity Operating Experience with Once-Through Steam Generators") was published (Ref. B-2). This report discussed the operating problems associated with Babcock & Wilcox steam generators. In February 1982, NUREG-0886 ("Steam Generator Tube Experience") was published (Ref. B-3). This report contained a summary of past and updated operating experience of all pressurized water reactor steam generators through December 1981. The update to the abnormal occurrence in NUREG-0090, Vol. 5. No. 2 contained a summary based on the information given in NUREG-0886.

Recently, NUREG-1063 ("Steam Generator Operating Experience Update 1982-1983") was published (Ref. B-4). This report highlights new operational events in domestic plants relating to steam generator integrity that occurred during 1982 and 1983, and updates inspection results reported during this period.

During the 1982-1983 period, three new problems were encountered in operating steam generators. These were (1) excessive tube vibration and accelerated tube wear in Westinghouse Model D and Model E steam generators, (2) loose parts in the secondary side of steam generators initiating damage to the outside diameter of tubes, and (3) widespread primary-side intergranular stress corrosion cracking of tubes in the tubesheet area resulting from sulfur ingress from the containment spray system containing sodium thiosulfate.

Design modifications to minimize excessive tube vibrations in Westinghouse Model D steam generators have been installed in operating plants, and recent inspections and tests indicate that the modifications are effective solutions to the accelerated wear problems.

Secondary-side inspections using fiberoptics and miniature video cameras have been successfully used in locating secondary-side loose parts so that effective retrieval could be accomplished. Loose parts monitoring systems have also been used to indicate the presence of loose parts in steam generators.

The tubes in the once-through steam generator that suffered widespread sulfur-induced stress corrosion cracking were repaired by means of a kinetic expansion process to form the tube against the tubesheet; that is, close the radial gap and produce an interference fit between the tube's outside diameter and the tubesheet drilled hole inside diameter to achieve a leaktight, load-carrying joint. In addition, sulfur removal was accomplished by cleaning all primary surfaces with a dilute solution of hydrogen peroxide.

During the 1982-1983 period, degradation mechanisms previously found in recirculating and once-through steam generators were still active but at a somewhat diminished rate as secondary water chemistry controls were tightened and secondary-side modifications were made. Tube sleeving and steam generator replacement also took place.

Operation of replacement steam generators, currently only Westinghouse Model 44 and 51 with Model F type material and design features, has apparently been trouble free.

Tables 1, 2, and 3 summarize operating experience through December 1983 for Westinghouse, Combustion Engineering, and Babcock & Wilcox steam generators (SGs), respectively. These tables are based on similar tables contained in NUREG-1063.

The NRC staff report of the proposed resolution of the unresolved safety issues associated with steam generators is expected to be issued for public comment during the latter part of 1984.

As noted above, Tables 1, 2, and 3 summarize operating experience through December 1983. During the first half of 1984, an additional event occurred which was considered significant. The event involved an SG tube failure at Fort Calhoun, resulting in an estimated maximum leak rate of 112 gpm. Fort Calhoun is a Combustion Engineering designed plant, operated by the Omaha Public Power District (the licensee) and is located in Washington County, Nebraska. The event is summarized below.

During Feburary 1984, 3 weeks before a scheduled refueling outage, the licensee detected a primary leak rate of approximately 0.2 gpd in SG B. During the outage, extensive eddy current testing (ECT) was conducted as part of the licensee's planned inservice inspection program and in support of a rimcut modification program. Fort Calhoun has two SGs, each containing 5,005 Inconel-600 tubes which are 0.75 inch outside diameter and 0.048 inch minimum wall thickness. Full length examinations were made of 1,454 tubes in SG A and 1,034 tubes in SG B. At the time of the testing, data evaluation detected only one previously known flaw in SG B. A total of nine tubes were plugged because they would not pass the 0.540 inch ECT probe.

On May 16, 1984, the licensee was conducting a hydrostatic test in preparation for returning to power operation. The cold-leg temperature was 398°F. The reactor coolant system (RCS) pressure was 1,800 psi and the SG pressure was 200 psi. While plant personnel were closely watching SG B for indications of the small leak experienced before shutdown, an unanticipated increase in water level indicated a tube failure. A high leak rate persisted for approximately 10 minutes, while the RCS pressure was decreased and the main steam line isolation valve associated with SG B was closed.

The failed tube was found in the second peripheral row from the outside. The failure was a 1¼-inch-long axial "fishmouth" opening along the tube bottom on the hot-leg side of the horizontal run at the top of the "U". Sections of the failed tube and adjacent tube were removed for laboratory analysis.

Analysis revealed the failure mode to be intergranular stress corrosion cracking (IGSCC) from the outside, through 95% of the wall thickness, with the remaining 5% evidencing ductile tearing. The tube cross section was ovalized. An additional defect, through approximately 50% of the wall, was found ¼ inch from the hot leg end of the fishmouth failure. This was similar to the first defect, except that it was oriented 45° to the tube axis. Tests indicated that the material was not sensitized. Microstructure was typical of mill annealed Inconel-600.

The failed tube was one that had been the subject of ECT in both 1982 and 1984. Review of the ECT tapes of those tests showed no flaw in 1982 but revealed an indication of a defect through 99% of the wall in 1984. Although this indication was unambiguous and not affected by interference, it was missed by the analyst who evaluated the 1984 tapes before the hydrostatic test. The second defect also was apparent in the 1984 ECT tapes and also was missed.

Prior to restart, the licensee performed ECT of all tubes in both SGs which were accessible with the remote probe insertion machine and which were not tested in 1984. The licensee reevaluated, with independent verification, the ECT data tapes for the tubes already tested in 1984. The licensee presented test results which indicated that tubes sufficiently ovalized to obscure serious defects from detection by ECT are sufficiently restricted to prevent passage of the 0.540-inch ECT probe. These tubes would be plugged on the basis of their restriction.

Fort Calhoun has always operated with an all-volatile-treatement secondary chemistry program. ECT examinations were conducted in 1975, 1976, 1977, 1978, 1981, and 1982. Very few degraded tubes were detected over this period, and the failed tube is the first defective tube detected. ECT conducted after the tube failure revealed another tube in SG B with a defect through 42% of the wall on the hot-leg side of the horizontal run at the top of the bundle. In addition, two tubes in SG A were found to have defects on the cold-leg side, near the tube sheet: one showed a defect through 39% of the wall, about 10 inches above the tube sheet; the other showed 2 defects 27% and 50% through the wall, 4 inches above the tube sheet.

The NRC has required the licensee to shut down the plant nine months after restart to perform additional SG tube inspections. On June 18, 1984, the NRC issued Inspection and Enforcement Information Notice No. 84-49 (Ref. B-5), which contained details of the event, to all pressurized water power reactor facilities holding an operating license or construction permit.

This item is generally considered closed for purposes of this report. However, it occasionally is reopened to report steam generator information considered significant.

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Table 1 Westinghouse Steam Generator Operating Experience Through 1983

Plant name	SG model no.	Operating license issuance date	Secondary water chemistry control †	Degradation type*	No. of leaking tubes	No. (%) of tubes plugged	Sleeve repairs (no. of tubes)	Notes
Yankee-Rowe	**	7/60	AVT***	D,S/SCC-IGA	38	123(2)	-	
San Onofre 1	27	3/67	Phosphate	D,W,F,S/SCC-IGA	31	954(8)	7000	
Ginna 1	44	9/69	AVT***	D,W,S/SCC-IGA	6	228(4)	99	
H.B. Robinson 2	-	9/70	-	-	-	-	-	1
Point Beach 1	44	12/70	AVT	-	-	-	12	2
Point Beach 2	44	11/71	AVT***	D,W,S/SCC-IGA	4	117(2)	4150	
Surry 1	51	5/72	AVT	-	-	-	-	3
Turkey Point 3	44	7/72	AVT	-	-	-	-	4
Surry 2	51	1/73	AVT	-	-	-	-	5
Turkey Point 4	44	4/73	AVT	-	-	-	-	6
Zion 1	51	4/73	AVT***	D,P/SCC	1	498(4)	-	
Prairie Island 1	51	8/73	AVT***	P,F	2	34(<1)	-	
Indian Point 2	44	9/73	AVT***	D,W	5	492(4)	-	
Zion 2	51	11/73	AVT***	D	1	13(<1)	-	
Kewaunee	51	12/73	AVT***	D	0	72(1)	-	
Cook 1	51	10/74	AVT	-	0	39(<1)	-	
Prairie Island 2	51	10/74	AVT	P,F,S/SCC-IGA	1	61(1)	-	
Haddam Neck	27	12/74	AVT***	D,W,F,S/SCC-IGA	4	69(0.5)	-	
Trojan	51	11/75	AVT	P/SCC	42	347(3)	-	
Indian Point 3	44	12/75	AVT	D,P	3	2053(16)	2970	
Beaver Valley 1	51	1/76	AVT	-	1	9(<0.1)	-	
Salem 1	51	8/76	AVT	D,F	0	101(0.5)	-	
Farley 1	51	6/77	AVT	P/SCC	8	282(3)	-	
North Anna 1	51	11/77	AVT	D,P/SCC	1	284(3)	-	
Cook 2	51	12/77	AVT	P/SCC	8	79(0.5)	-	
Salem 2	51	4/80	AVT	F	0	0	-	
North Anna 2	51	8/80	AVT	-	0	284(3)	-	
Sequoyah 1	51	9/80	AVT	D	0	0	-	
Farley 2	51	10/80	AVT	-	5	5(<0.1)	-	
McGuire 1	D2	1/81	AVT	F	-	87(0.5)	-	
Diablo Canyon 1	51	9/81	AVT	-	-	-	-	
Sequoyah 2	51	9/81	AVT	P/SCC	1	1(<0.1)	-	
Summer	D3	3/83	AVT	-	-	-	-	

Table 1 (cont'd)

†AVT = all-volatile treatment
*D = denting, S/SCC-IGA = secondary-side stress corrosion cracking/intergranular attack, W = wastage,
F = fretting, P/SCC = primary-side stress corrosion cracking, P = pitting.
**No model number. Yankee-Rowe uses 304 stainless steel tubing; all other PWRs use Inconel 600 tubing.
***Started on phosphate water chemistry.

Notes to Table 1:

(1) Replacement of SGs at H.G. Robinson 2 is in progress.
(2) Point Beach 1 SGs were replaced during 1984 with Model 44F.
(3) Surry 1 SGs were replaced during 1981 with Model 51F.
(4) Turkey Point 3 SGs were replaced during 1982 with Model 44F.
(5) Surry 2 SGs were replaced during 1980 with Model 51F.
(6) Turkey Point 4 SGs were replaced during 1983 with Model 44F

Table 2 Combustion Engineering* Steam Generator Operating Experience Through 1983

Plant name	Operating license issuance date	Secondary water chemistry control†	Degradation type**	No. of leaking tubes	No. (%) of tubes plugged	Sleeve repairs (no. of tubes)
Palisades	3/71	AVT***	D, W, P, S/SCC	2	3750(22)	33
Maine Yankee	9/72	AVT	D	0	37(<1)	-
Fort Calhoun	5/73	AVT	W	0	3(<1)††	-
Calvert Cliffs 1	8/74	AVT	D	0	12(<1)	-
Millstone 2	8/75	AVT	D, P	2	1702(10)	2022
St. Lucie 1	3/76	AVT	D, P	1	130(<1)	-
Calvert Cliffs 2	8/76	AVT	D	0	5(<1)	-
Arkansas 2	9/78	AVT	D	0	122 (<1)	-

†AVT = all-volatile treatment

††Tubes were plugged because they are used to structurally support the support plate, not because of any degradation.

*Combustion Engineering steam generators do not have specific model numbers. For the plants listed above, the steam generators are of the same basic design with the exception of Palisades. Palisades uses drilled hole support plates for the lower six tube supports instead of egg crate supports.

**D = denting, W = wastage, P = pitting, S/SCC = secondary-side stress corrosion cracking.

***Started on phosphate water chemistry.

Table 3 Babcock & Wilcox* Steam Generator Operating Experience Through 1983

Plant name	Operating license Issuance date	Degradation type**	No. of leaking tubes	No. (%) of tubes plugged	Sleeve repairs (no. of tubes)
Oconee 1	2/73	F, E/C	11	337(<2)	16
Oconee 2	10/73	F, E/C	3	39(<1)	-
Arkansas 1	5/74	E/C, IGA	3	149(<1)	-
Oconee 3	7/74	F, E/C	5	116(<1)	-
Rancho Seco 1	8/74	F, E/C	3	20(<1)	-
Three Mile Island 1†	10/74	E/C, IGSCC	***	1204(<4)	-
Crystal River 3	1/77	E/C	0	33(<1)	-
Davis-Besse 1	4/77	E/C	2	27(<1)	-
Three Mile Island 2††	2/78	-	-	38(<1)	-

*Babcock & Wilcock (B&W) steam generators do not have specific model numbers, but are of the same basic design. B&W plants have been operated exclusively with all-volatile treatment secondary water chemistry control.

**F = fatigue cracking, E/C = erosion/corrosion, IGA = intergranular attack, IGSCC = intergranular stress corrosion cracking.

***Multiple leaks were revealed during hydrostatic tests in November 1981.

†Three Mile Island 1 remains shutdown following the March 28, 1979 accident at Three Mile Island 2.

††The Three Mile Island 2 reactor was severely damaged during the accident on March 28, 1979. Its authority to operate was suspended.

79-3 Nuclear Accident at Three Mile Island

This abnormal occurrence was originally reported in NUREG-0090, Vol. 2, No. 1, "Report to Congress on Abnormal Occurrences: January-March 1979," and updated in subsequent reports in this series, i.e., NUREG-0090, Vol. 2, No. 2; Vol. 2, No. 3; Vol. 2, No. 4; Vol. 3, No. 1; Vol. 3, No. 2; Vol. 3, No. 3; Vol. 3, No. 4; Vol. 4, No. 1; Vol. 4, No. 2; Vol. 4, No. 3; Vol. 4, No. 4; Vol. 5, No. 1; Vol. 5, No. 2; Vol. 5, No. 3; Vol. 5, No. 4; Vol. 6, No. 1; Vol. 6, No. 2; Vol. 6, No. 3; Vol. 6, No. 4; and Vol. 7, No. 1. It is further updated as follows.

Reactor Building Entries

During the secondary calendar quarter of 1984, 54 entries were made into containment. There have been a total of 401 entries since the March 28, 1979 accident. Major activities included preparing for the removal of the reactor vessel head in late July or early August of this year. This includes the completion of the reactor coolant system depressurization and draindown, the installaton of the canal seal plate, control rod drive leadscrew parking, refueling canal preparation, auxiliary fuel handling bridge modifications, radiation shielding instrumentation installation, TV camera installation, dose reduction activities and internal fixture modifications.

EPICOR-II/Submerged Demineralizer System (SDS) Processing

The EPICOR-II system processed approximately 28,000 gallons of water during the second quarter of 1984. The SDS processed approximately 241,000 gallons of water during the same time period.

EPICOR-II/Prefilter and SDS Liner Shipments

Two EIPCOR-II liners were shipped from the TMI site to Hanford, Washington, during this reporting period.

Auxiliary and Fuel Handling Building Activities

Decontamination activities continued during this quarter. Major efforts were in the reactor coolant bleed tank and decay heat pump cubicles. Work on the decontamination and removal of the tanks in the "A" fuel pool also continued. Progress was also made on the installation of the reactor building cooling (chiller) system.

NUREG-0732 Update

Revision 1 to NUREG 0732, "Answers to Frequently Asked Questions About Cleanup Activities at Three Mile Island, Unit 2", was issued (Ref. B-6). The document covers the full range of TMI-2 cleanup issues, including: goals, progress, and remaining tasks; details on building and accident water decontamination; issues regarding fuel removal and the packaging and transportation of radioactive wastes; potential social, economic, and environmental impacts, including monitoring and the potential for accidents; worker exposure and safety concerns; and the schedules and funding for the cleanup.

Decay Heat Removal System Back in Service

One train of the Unit 2 decay heat removal system was tested and declared operable during this quarter. The decay heat removal system was contaminated during the 1979 accident. Due to system internal contamination and high dose rates in the vicinity of decay heat removal system components, the system had not operated for more than five years. Once the area was decontaminated, maintenance personnel changed component oil, adjusted valve limit switches, and rotated the decay heat pump internals by hand. The system was activated in the pump recirculation mode and operated normally. The operable train of the decay heat removal system will now be tested monthly per the technical specification surveillance requirements. Decontamination of the other decay heat removal train is in progress.

There are no plans to operate the decay heat removal system in the core cooling mode since the remaining core heat (17.5 kilowatts) is being adequately dissipated to the reactor building by purely passive means. The decay heat system is addressed in several emergency procedures and is available as a backup for decay heat removal. In some accident scenarios, the system could be brought into service for reactor vessel refill in the event of unisolable reactor coolant system leaks. In the refill mode, several low capacity refill systems would normally be activated before the decay heat system would be utilized.

GPU Nuclear Director Change

GPU Nuclear Corporation (GPUNC) and Bechtel North American Power Corporation jointly announced on June 7, 1984 that Mr. Bahman K. Kanga, who has served for two years as Director of the TMI-2 cleanup, will transfer during August 1984 to an assignment within the Bechtel organization. Mr. Franklin Standerfer will join GPUNC on July 23, 1984 to replace Mr. Kanga as Director, TMI-2. Mr. Standerfer has served as Assistant Manager for Defense and Energy Programs at the U.S. Department of Energy's Richland Operations Office.

TMI-2 Advisory Panel Meetings

On April 12, 1984, the Advisory Panel for the Decontamination of TMI-2(Panel), held a meeting in Harrisburg, Pennsylvania. Dr. Ronnie Lo, of the NRC TMI Program Office (TMIPO), made a presentation on the NRC staff's December 1983 Supplement to the Programmatic Environmental Impact Statement (PEIS) dealing with worker radiation exposure. Mr. J. Hildebrand, from GPUNC, discussed GPUNC's program to limit worker radiation exposures to as low as reasonably achievable (ALARA) levels. The present program and program results were described.

On April 19, 1984, Dr. Bernard Snyder, (Director, TMIPO) and Dr. Frank Congel (Chief, Radiological Assessment Branch, NRC Office of Nuclear Reactor Regulation) addressed the members of the Panel on health research studies of the Pennsylvania Department of Health. The major point of discussion was the reassessment of worker exposure and radiation protection measures employed at TMI-2.

On May 30, 1984, the Panel met with the NRC in Washington, DC. The Panel brought up a number of topics for discussion. Mr. Arthur Morris, Chairman of the Panel, asked the Commissioners to reconsider the Commissioners' earlier decision not to link the restart of TMI-1 to a firm funding plan for the cleanup of TMI-2. The Commission reiterated its position that they have no legal basis for conditioning the restart of TMI-1 to a funding plan for TMI-2. The principal concern of the Panel was the slow pace of the cleanup due partially to the lack of sufficient funds. After considerable discussion, the Commission, citing the slow pace of the cleanup effort, requested that the NRC staff prepare a draft Commission Order for Commission review which will require the licensee to accomplish certain milestones in the cleanup effort within specified time periods.

The Panel brought up the issue of funding; both the Panel and the Commission agreed that adequate funding for the cleanup will become a critical issue after this calendar year.

The Panel and the Commission also discussed a proposal, originally suggested by Mr. Thomas Gerusky, Panel member from the Commonwealth of Pennsylvania, that the NRC explore the possibility of redefining the endpoint of the cleanup. In the interest of minimizing worker radiation exposure, final decontamination of the facility could be deferred indefinitely provided that adequate protection of the public could be assured. The Commission will look into the policy questions of such a proposal.

On June 14, 1984, the Panel held a meeting in Harrisburg, Pennsylvania. The Chairman of the Panel, Mr. A. Morris, provided a short summary of the Panel's May 10, 1984, TMI-2 site tour and the May 30, 1984 meetings with White House staff members and the NRC Commissioners. Both May 30th meetings were held in Washington, DC.

Dr. W. Bixby, DOE Site Manager, provided an update of DOE activities related to TMI-2. Dr. Bixby provided information on the 1984 DOE funding level for the cleanup and the current status of DOE's agreement with GPUNC concerning DOE's acceptance of TMI-2 generated abnormal wastes.

Mr. S. Hultman, GPUNC, presented a summary of the licensee's planned reactor pressure vessel head lift stressing the licensee's activities to assure safe removal of the reactor pressure vessel head.

Dr. B. Snyder, Director, TMIPO, provided a short explanation of the NRC's safety review of the licensee's program for the reactor pressure vessel head lift.

Mr. P. Clark, President of GPUNC, summarized the 1984 funding situation for the cleanup of the damaged reactor. Mr. Clark stated that $93.2 million is available in the calendar year of 1984 for TMI-2 cleanup related activities. He stated that the company is aiming for a mid-1985 date for the initiation of fuel removal from the reactor pressure vessel. Mr. Clark also mentioned that the company has a request before the Pennsylvania Public Utilities Commission (PaPUC) to allow $17 million annually, that is presently being used to amortize the TMI-2 debt, to be applied to the cleanup effort. The Panel approved a motion endorsing the company's request before the PaPUC and will inform the PaPUC in writing of the Panel's position on this issue.

Future reports will be made as appropriate.

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80-2 Transient Initiated by Partial Loss of Power

This abnormal occurrence was originally reported in NUREG-0090, Vol. 3, No. 1, "Report to Congress on Abnormal Occurrences: January-March 1980." It was updated in NUREG-0090, Vol. 3, No. 3 and subsequently closed out in NUREG-0090, Vol. 4, No. 2. It is being reopened to report some additional events involving various degrees of loss of power at Babcock & Wilcox (B&W) designed plants, and corrective actions being taken.

NUREG-0090, Vol. 3, No. 1 described an event on February 26, 1980 at Crystal River Unit 3 which involved a partial loss of non-nuclear instrumentation (NNI) and subsequent false control signals to be sent to the integrated control system (ICS). Crystal River Unit 3 is a B&W - designed pressurized power reactor operated by Florida Power Corporation and located in Citrus County, Florida. The NNI/ICS problem resulted in a reactor trip (due to high reactor pressure) and turbine trip; the opening of the pressurizer power operated relief valve (PORV), the pressurizer spray valve, and a code safety valve; decreased feedwater flow to the steam generators; activation of the engineered safety features (ESF) systems; and discharge of about 43,000 gallons of primary coolant into the containment building.

The event was one of several involving failures of the NNI or ICS which had occurred at various B&W-designed plants since December 1974. Because of the sensitivity of the B&W design to certain transients, including those caused by malfunctions of the NNI/ICS, significant efforts were expended both by the NRC and the industry to determine corrective actions regarding system and operator procedure changes, and improved operator training, to mitigate the effects of such events. The NRC issued Orders to all licensees with B&W-designed plants with actions to be taken, including recommendations made in a joint report by the industry's Institute of Nuclear Power Operations and the Nuclear Safety Analysis Center (Ref. B-7). After resolution with the affected licensees, the Orders were terminated.

As previously reported, even after following the implementation of all of the required and intended corrective actions on the B&W plants, there could be no guarantee that transients similar to the above described Crystal River Unit 3 event can be completely eliminated. However, it was believed that occurrence of such events would be less frequent and of less consequence. Thus, the corrective actions should provide an increased margin of assurance to the health and safety of the public.

Since the February 26, 1980, event at Crystal River Unit 3, through May 1984, there have been only four events, resulting in various degrees of power loss, due to NNI/ICS faults at B&W plants. The first event occurred at Davis Besse on June 30, 1981. The plant is operated by Toledo Edison Company and is located in Ottawa County, Ohio. Wiring anomalies discovered during transfer of power caused a partial loss of NNI a.c. power, which led to the loss of 16 NNI signals. There was no plant impact since the plant was in cold shutdown at the time. The wiring anomalies were corrected.

The second event also occurred at Davis Besse, on January 18, 1983. While the plant was operating at 99% power, a partial loss of NNI occurred due to a short to ground within the a.c. power for the operating range level recorder for steam generator No. 2. As a result, there was a loss of NNI power to certain a.c. devices, and invalid NNI signals to the ICS led to a reactor trip on high reactor coolant pressure. As corrective actions, fusing was added to the ICS and externally mounted instrumentation.

The third event occurred at Rancho Seco on March 19 and 20, 1984. The plant is operated by Sacramento Municipal Utility District and is located in Sacramento County, California. As discussed further in Item 2, Appendix C of this report, a major hydrogen explosion and subsequent fire occurred in the excitor to generator housing interface at about 9:50 p.m. on March 19, 1984. Twice within the next few hours, the plant experienced a partial loss of NNI power. The first occurred about an hour after the explosion, due to a degraded inverter coupled with the failure of a -24V d.c. power supply, subsequently leading to a loss of one string (out of three) of NNI power.

The operators, however, perceived a total loss of NNI power and followed casualty procedures for such an event. These procedures, in part, entail initiation of high pressure injection. This injection increased the reactor coolant system's pressure and resulted in a pressurizer code safety valve lifting prematurely at 2360 psig (set point is 2500 psig). The reactor coolant system decreased in pressure and the pressurizer code safety valve reseated; pressure increased again due to continued high pressure injection and the same pressurizer code safety valve again lifted. While the pressurizer code safety valve lifted for the second time, the high pressure injection valves were being throttled. Reactor system pressure was then controlled per procedure. Four minutes after the perceived loss of total NNI power, NNI power was regained, and high pressure injection was secured.

The second partial loss of NNI occurred about three hours after the hydrogen explosion and lasted about five minutes. This loss occurred while trouble shooting the NNI train which had failed earlier. The cause was due to low voltage on an inverter which did not permit an automatic transfer of load to it when another inverter was normally tripped during the trouble shooting process. The operators correctly recognized the problem as a partial loss of NNI power, rather than a total loss; therefore, there was no high pressure injection or challenges to the safety valves.

The NRC sent a team to the plant on March 29 and 30, 1984, to gather information regarding the partial losses of NNI power. The NRC studied the event in detail, including the design of the system, operator procedures and response to the event, and the corrective actions taken by the licensee (which consisted primarily of implementing periodic calibration of power supply alarm ad trip setpoints). The purpose of the study was to determine whether additional actions may be necessary.

While the above study was being made, a fourth event occurred on April 26, 1984, at Crystal River Unit 3, the same plant at which the previously described February 26, 1980, event occurred. While operating at 97% reactor power, the power supply for one string of NNI failed due to the failure of a capacitor with the wrong ratings installed by the manufacturer. The failed NNI string therefore sent erroneous signals to the ICS. The ICS rapidly reduced main feedwater flow to the "B" steam generator causing an undercooling transient, and the reactor subsequently tripped on high reactor coolant system pressure.

As corrective actions, the licensee replaced the failed capacitor and inspected similar capacitors to assure they were of the correct ratings. The licensee is also pursuing installation of a redundant 24 V d.c. power supply.

Though the cause of the April 26, 1984, event was similar to that of the February 26, 1980, event, the consequences of the 1984 event were considerably less. For example, the pressurizer power operated relief valve did not open, no reactor coolant safety valves opened, there was no initiation of high pressure injection, and there was no release of water into the reactor containment building from the reactor coolant system. The licensee attributes the reduced consequences to the corrective actions taken since the February 26, 1980, event.

In view of the recent events at Rancho Seco and Crystal River Unit 3, the NRC requested a meeting with the B&W Owners Group to review the NNI status at B&W-designed plants. This meeting was held at the NRC on July 12, 1984.

The NRC continues to review the situation, including the improvements made since 1980. If necessary, the NRC may request that the licensees take additional action.

This incident is closed for purposes of this report.

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83-5 Large Diameter Pipe Cracking in Boiling Water Reactors (BWRs)

This abnormal occurrence was originally reported in NUREG-0090, Vol. 6, No. 3, "Report to Congress on Abnormal Occurrences: July-September 1983," and updated in a subsequent report in this series, i.e., NUREG-0090, Vol. 6, No. 4. It is further updated as follows.

As discussed in the last updating report, the BWR licensees have completed the pipe inspections as required by the NRC. The most significant information since the last report is that Philadelphia Electric Company decided to undertake a pipe replacement program for Peach Bottom Unit 2. The licensee shut down the plant on April 27, 1984, for an extended outage which includes the pipe replacement program.

The NRC has established a new multiplant action (MPA) item to track the BWR pipe crack issue. This new MPA item is designated B-84, "Inspection of BWR Stainless Steel Piping (Generic Letters 84-11 and 84-11A)." Since the new MPA item will be tracked through NUREG-0748, "Operating Reactors Licensing Actions Summary," (Ref. B-8), which is published monthly, it will no longer be reported in the NUREG-0090 report series.

Therefore, this incident is closed for purposes of this report.

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83-7 Improper Control Rod Manipulations

This abnormal occurrence was originally reported, and closed out, in NUREG-0090, Vol. 6, No. 3, "Report to Congress on Abnormal Occurrences: July-September 1983." The report described events at two plants (i.e., Quad Cities Unit 1 and Hatch Unit 2), involving improper control rod insertions and other violations, which demonstrated breakdowns in plant management control systems designed to control operations activities and ensure safe operation of the facilities. The previous report is being updated to include similar events at two other plants.

Peach Bottom Unit 3

Peach Bottom Unit 3 is a General Electric designed boiling water reactor plant located in York County, Pennsylvania. The plant is operated by Philadelphia Electric Company (the licensee).

On November 17, 1983, Unit 3 was being shut down to replace a main steam safety relief valve. At 10:30 p.m., at about 21% power, a turbine high vibration alarm was received. The operators then utilized a licensee approved accelerated shutdown procedure which permitted use of individual rod scramming from the scram timing test panel. By 10:34 p.m., ten rods were scrammed and the turbine taken offline. An additional 25 rods were individually scrammed when at 10:36 p.m. a scram discharge instrument volume (SDIV) high level rod block annunciated. Individual rod scramming was suspended; however, a SDIV high level scram followed shortly. Since many individual rod scram switches were left in the scram position, flow into the SDIV volume exceeded the drain capacity and resulted in the scram.

Following the event, the licensee promptly issued instructions to the operators to limit both the rate of individual rod scrams and the number of switches remaining in the scram position.

The NRC Resident Inspectors questioned the licensee's justification for individually scramming rods, in light of rod worth minimizer (RWM) and rod sequence control system (RSCS) operability requirements. The practice had been permitted by licensee procedures for several years (since 1977) and took some time to research its origin and justification. Consequently, pending further justification, on December 1, 1983, the licensee committed to suspend the use of individual rod scrams for purposes other than testing or anticipated transient without scram (ATWS) response.

An NRC special inspection (Ref. B-9) was conducted on January 5-20, 1984, which included an onsite management meeting with senior licensee personnel on January 12, 1984. This inspection reviewed the practice of individually scramming control rods for normal shutdown and the November 17, 1983 event. A violation was identified involving changes to the facility and facility procedures to allow individual scramming of control rods without an adequate safety review as required by 10 CFR § 50.59 to determine if the changes involved a modification to technical specifications or an unreviewed safety question.

On April 12, 1984, at an enforcement conference (Ref. B-10) between senior NRC Region I and licensee management, the NRC stated that the individual rod scramming violation appeared to be caused by an inadequate review of procedure changes associated with normal plant shutdown. The safety significance of individual rod scramming is the potential for a rod drop accident that could result in fuel damage. The licensee acknowledged the event and causes. The licensee presented the results of a General Electric study, subsequently transmitted to NRC Region I on April 23, 1984, which concluded that no safety problem existed when the reactor was above 10% power. The study also indicated that below 10% power the results were outside the design basis for the rod drop accident.

The licensee noted that details of the review for the 1977 procedural change, that allowed individual rod scramming, had to be reconstructed from memory in that the justification used in making such procedural changes was not well documented at that time. The licensee stated he would stop the practice of individually scramming control rods, revise appropriate procedures, strengthen procedural controls and the Plant Operations Review Committee (PORC) will better document their reviews of procedure changes.

On June 18, 1984, an Order Modifying License Effective Immediately was issued (Ref. B-11) requiring the licensee to submit within 60 days to the NRC Regional Administrator, Region I, for review and approval, a plan for an appraisal of: (1) the licensee's process for performing safety evaluations and reviews of procedures pursuant to 10 CFR § 50.59 to determine if the process is currently effective or if improvements are needed; (2) plant and system operating procedures to verify that the existing procedures are consistent with technical specifications, technical specification bases, and those sections of the final safety analysis report concerning systems necessary to mitigate design basis accidents, and do not involve unreviewed safety questions; and (3) the licensee's program for ensuring employees involved in the review and approval of operating procedures remain cognizant of the licensing bases.

Browns Ferry Unit 1

Browns Ferry Unit 1 is a General Electric designed boiling water reactor plant located in Limestone County, Alabama. The plant is operated by the Tennessee Valley Authority (the licensee).

During a controlled shutdown on January 6, 1984, a decision was made to reduce power rapidly to clear an average power range monitor (APRM) high signal (half scram). The reactor was manually scrammed at 11:02 p.m. when it was recognized that the reactor may have an abnormal rod pattern. During the power reduction, a second licensed operator was assigned to verify the proper positioning of the control rods and the rod worth minimizer (RWM) was bypassed at 11:38 p.m. as permitted by the technical specifications with an inoperable RWM with the reactor at about 12% power. Control rods were inserted using the rod out notch override (RONOR) switch which defeated the function of the rod sequence control system (RSCS). One control rod was inserted two notches further than permitted by the RWM and several rods were inserted from 2 to 24 steps further into the reactor core than would have been permitted by the RSCS. The RONOR switch defeats the functions of the RSCS by eliminating the rod settle signal for each step of movement that the RSCS uses to prevent the rods in a group from being moved more than one step from the other rods in that group. Both the RCSC and the RWM systems are backup to procedural controls to limit control rod reactivity insertions during startups and shutdowns below 30% power. The technical specifications require both the RSCS and the RWM to be operable below 20% power. In the followup to this event, it was determined that during a shutdown on Unit 3 on September 6-7, 1983, control rods were moved in four instances without the RSCS enforcing notch control. None of the above described events resulted in fuel damage.

The cause of the event was due to incorrect use of the RONOR switch. Although a plant supervisor issued a memorandum on June 9, 1983, authorizing the use of the RONOR switch to insert individual rods doring a controlled shutdown, the memorandum had not received the proper review and approval for a change to operating procedures and was contrary to the technical specifications.

The licensee's corrective actions included the following: the memorandum "authorizing" the use of the RONOR switch during a controlled shutdown was withdrawn and the procedure relating to the RONOR switch was revised; discussions were held with the manager involved in issuing the memorandum "authorizing" use of the RONOR switch to emphasize that procedures shall be formally revised rather than clarified by memorandum; all operators and nuclear engineers were given supplemental training concerning this event and similar events at other facilities; use of the RONOR switch will be incorporated in the requalification training program and the lesson plans for new operators; and administrative instructions were issued that prohibit use of the RONOR switch "emergency in" function, except for the correction of RSCC notch logic errors, and prohibit the bypassing of the RWM if it is operable.

The NRC Region II performed a special inspection on January 16-19, 1984, of the circumstances associated with this event. Four violations were identified involving: failure to follow procedures; failure to perform a 10 CFR § 50.59 safety evaluation prior to changing procedures described in the final safety analysis report; bypassing the RSCS; and bypassing the RWM. An enforcement conference was conducted by the NRC on February 24, 1984, with the licensee.

On May 11, 1984, the NRC Region II sent a letter to the licensee enclosing a Notice of Violation and Proposed Imposition of Civil Penalty in the amount of $60,000 (Ref. B-12). In addition, the NRC letter requested the licensee to address a number of questions concerning operator training, adequacy of procedures, flow of information, administrative controls for maintaining operating procedures, and the identification of root causes of events and initiation of comprehensive corrective actions to prevent recurrence. The licensee responded on June 11, 1984, including payment of the civil penalty.

The NRC will follow the corrective actions taken by the licensees of Peach Bottom Unit 3 and Browns Ferry Unit 1 to assure that the issues are properly addressed.

This item is closed for purposes of this report.

APPENDIX C

OTHER EVENTS OF INTEREST

The following events are described below because they may possibly be perceived by the public to be of public health significance. The events did not involve a major reduction in the level of protection provided for public health or safety; therefore, they are not reportable as abnormal occurrences.

1. Control Rod Drive Guide Tube Support Pin Failures in Some Westinghouse Designed Plants

Some Westinghouse designed pressurized water reactor plants have been experiencing stress corrosion cracking of the control rod drive (CRD) guide tube support pins. The pins are used to align the bottom of the CRD guide tube assemblies with the top of the upper core plate. Two support pins are bolted into the bottom plate of each lower guide tube assembly and are inserted into the top of the upper core plate in a manner that provides lateral support while accommodating thermal expansion of the guide tube assembly relative to the core plate. The pins are about 3 1/2 inches long and have a diameter of 0.507 or 0.537 inch (depending upon reactor design).

The pin assembly consists of: (1) the pin which is of clothespin shape with integral bolt and flange with an overall length of about 3 1/2 inches, (2) a threaded sleeve which serves as the nut, and (3) a locking device consisting of a plug and pin that are welded to one another after the pin is installed and pre-loaded.

Pin and sleeve material is Inconel X-750 which, depending on the manufacturer and the fabrication date, has been solution treated and age hardened at various combinations of temperature and time. Following failure of these pins at various plants, Westinghouse stated that pins solution heat treated in the range 2000 $\pm$ 25°F would not be expected to fail in stress corrosion. Further, Westinghouse also redesigned the shank-flange radius to reduce stress concentration and to reduce installation pre-loads.

Item 3, Appendix C, of NUREG-0090, Vol. 5, No. 2 ("Report to Congress on Abnormal Occurrences: April-June 1982"), described Virginia Electric and Power Company's discovery during May 1982 that many of these pins had failed in North Anna Unit 1 (located in Louisa County, Virginia). The failures were found during a refueling outage, which had begun a week earlier than planned since the Loose Parts Monitoring System had detected possible foreign objects in a steam generator (SG). Inspection showed that a lock nut and a part of a support pin had caused extensive damage to the tube ends in two SGs; however, the licensee (and Westinghouse) did not consider the damage to be significant such as to prevent testing of the SGs or to affect their performance.

The licensee replaced all 61 guide tube assemblies with support pins incorporating design changes recommended by Westinghouse.

The event at North Anna Unit 1, a non-UHI (upper head injection) plant, resulted in no effect on public health and safety. When possible foreign objects were detected in the SGs, the licensee took expeditious corrective actions before serious consequences occurred.

Prior to the event at North Anna Unit 1, these failures had occurred only at foreign Westinghouse reactors in Japan and France. Pin failures have occurred with both Westinghouse and a foreign firm-supplied pins. The first failures were detected in early 1978 at a Japanese Plant.

The consequences of pin failure for plants with the UHI design was originally considered more acute than those for non-UHI plants. This concern was due to the potential for guide tube assembly misalignment in UHI plants upon pin failure. However, the domestic operating UHI plants have support pins meeting the recommended material process standards and the pin body design has been revised to prevent control rod misalignment upon pin failure. Non-UHI plants, which use the previous type support pins, may be expected to experience such support pin failures.

NRC Inspection and Enforcement Information Notice No. 82-29 was issued on July 23, 1982 to notify licensees with Westinghouse designed plants of the problem (Ref. C-1).

In March 1984, Wisconsin Electric Power Company inspected the support pins in Point Beach Unit 1 (located in Manitowoc County, Wisconsin) in response to the Information Notice. Based on ultrasonic testing, 67 of 74 pins showed crack indications. It was also found that three nut-shank assemblies were missing. The pins, similar to the North Anna Unit 1 situation, were manufactured prior to the revised Westinghouse design.

The licensee returned Point Beach Unit 1 to power without performing any repair based upon the safety analysis prepared by Westinghouse which indicated that there was no safety issue involved. This rather extensive safety analysis presented various scenarios in which damage might occur to a number of components. However, the overall thrust of the safety analysis was that the loose parts generated by guide pin failure do not create a safety concern, i.e., on the basis of no serious consequences.

Recently, pin failures were identified in Trojan (operated by Portland General Electric Company and located in Columbia County, Oregon). This incident is currently under evaluation by the licensee, Westinghouse, and the NRC staff. At least three pins were reported to be broken and SG damage was found. All pins have been replaced and the SG damage has been repaired.

2. Main Generator Hydrogen Explosion and Fire

On March 19, 1984, a hydrogen explosion and fire occurred in the main generator housing at the Rancho Seco Nuclear Generating Station. Rancho Seco is a Babcock and Wilcox designed pressurized water reactor located in Sacramento County, California. The Unit is operated by the Sacramento Municipal Utility District (the licensee).

On March 19, 1984, the plant was operating at 92 percent power. At approximately 8:50 p.m., a turbine gland steam exhauster fan tripped (2E1 bus) on an electrical ground fault. This caused the power supply breaker to the 2E1 bus to open and de-energize the 2E1 bus. Attempts to reclose this breaker failed. Among the equipment powered from the 2E1 bus is the hydrogen seal oil pump, which supplies oil for the hydrogen side seals of the Westinghouse main generator. Hydrogen gas is used to cool the main generator. By plant procedures, the main generator can continue operation with the air side seal oil pump maintaining shaft seals. Nevertheless, the loss of the hydrogen seal oil pump resulted in the escape of hydrogen from the generator. At approximately 9:49 p.m., after an equipment attendant checked some instrumentation in the turning gear area, a small explosion occurred. The equipment attendant called the control room and reported the explosion. The control room operators began to decrease reactor power at the maximum rate. At 9:50 p.m., a major explosion and subsequent fire occurred in the excitor to generator housing interface. The turbine and reactor were manually tripped. Reactor power at the time of the trip was 85 percent. The fire was extinguished by the carbon dioxide fire protection system within fourteen minutes of the explosion. At 9:53 p.m., the incident was declared an Unusual Event.

All systems responded normally to the reactor trip except one turbine bypass valve. This turbine bypass valve stuck open and was identified and shut within six minutes. The stuck open bypass valve resulted in the reactor coolant system experiencing a cooldown rate of 80°F/hr. which is within technical specification limits (i.e., 100°F/hr).

At approximately 10:57 p.m., with the plant in a stable condition, the control room operators perceived a total loss of non-nuclear instrumentation (NNI) power. The operators' actions included following the casualty procedure for the complete loss of NNI power. However, only a partial loss of NNI power actually occurred. The consequences of the operator actions are described in more detail in Appendix B of this report, specifically, the update to previously reported abnormal occurrence 80-2. Due to the loss of NNI power, the licensee upgraded the incident to an Alert status. When NNI power was regained about four minutes later, the Alert status was downgraded to an Unusual Event.

The event was maintained at an Unusual Event status by the licensee because the supply of carbon dioxide had been used to extinguish the fire. Fire watches were posted in all areas where carbon dioxide is used for fire protection. The event was secured from an Unusual Event at 6:00 p.m., after the carbon dioxide tanks had been refilled.

The impact of the explosion and fire on public health and safety was minimal; therefore, the event is not considered reportable as an abnormal occurrence. The event received both local and national media interest following issuance of several news releases by the licensee during the course of the event.

REFERENCES
(FOR APPENDICES)

B-1 U.S. Nuclear Regulatory Commission, "Summary of Operating Experience with Recirculating Steam Generators," USNRC Report NUREG-0523, published March 1979.*

B-2 U.S. Nuclear Regulatory Commission, "Summary of Tube Integrity Operating Experience with Once-Through Steam Generators," USNRC Report NUREG-0571, published March 1980.*

B-3 U.S. Nuclear Regulatory Commission, "Steam Generator Tube Experience," USNRC Report NUREG-0886, published February 1982.*

B-4 U.S. Nuclear Regulatory Commission, "Steam Generator Operating Experience Update 1982-1983," USNRC Report NUREG-1063, published June 1984.*

B-5 U.S. Nuclear Regulatory Commission, Inspection and Enforcement Information Notice No. 84-49, "Intergranular Stress Corrosion Cracking Leading to Steam Generator Tube Failure," June 18, 1984.**

B-6 U.S. Nuclear Regulatory Commission, "Answers to Frequently Asked Questions About Cleanup Activities at Three Mile Island, Unit 2," Docket No. 50-320, USNRC Report NUREG-0732, published August 1982;* Revision 1 to NUREG-0732 published March 1984.*

B-7 Letter from E.P. Wilkinson and E.L. Zebroski, Nuclear Safety Analysis Center/Institute of Nuclear Power Operations, to Harold Denton, Director, NRC Office of Nuclear Reactor Regulation, "Report on Crystal River Unit 3 Incident of February 26, 1980, by NSAC and INPO," March 11, 1980.**

B-8 U.S. Nuclear Regulatory Commission, "Operating Reactors Licensing Actions Summary (Orange Book)," USNRC Report series NUREG-0748, published monthly.*

B-9 Letter from Richard W. Starostecki, Director, Division of Project and Resident Programs, NRC Region I, to S.L. Daltroff, Vice President Electric Production, Philadelphia Electric Company, forwarding NRC Region I Combined Inspection Report 50-277/84-01 and 50-278/84-01, Docket Nos. 50-277 and 50-278, February 29, 1984.**

*Available in NRC Public Document Room, 1717 H Street, NW., Washington, DC 20555, for inspection. Available for purchase from NRC-GPO Sales Program, Division of Technical Information and Document Control, U.S. Nuclear Regulatory Commission, Washington, DC 20555.

**Available in NRC Public Document Room, 1717 H Street, NW., Washington, DC 20555, for inspection and copying (for a fee).

B-10 Letter from Richard W. Starostecki, Director, Division of Project and Resident Programs, NRC Region I, to S.L. Daltroff, Vice President Electric Production, Philadelphia Electric Company, forwarding NRC Region I Enforcement Conference Report 50-277/84-11 and 50-278/84-11, Docket Nos. 50-277 and 50-278, May 14, 1984.**

B-11 Letter from R. C. DeYoung, Director, NRC Office of Inspection and Enforcement, to V. Boyer, Senior Vice President-Nuclear, Philadelphia Electric Company, forwarding an Order Modifying License Effective Immediately, Docket Nos. 50-277 and 50-278, June 18, 1984.**

B-12 Letter from James P. O'Reilly, Regional Administrator, NRC Region II, to H.G. Parris, Manager of Power and Engineering, Tennessee Valley Authority, forwarding a Notice of Violation and Proposed Imposition of Civil Penalty, Docket Nos. 50-259, 50-260, and 50-296, May 11, 1984.**

C-1 U.S. Nuclear Regulatory Commission, Inspection and Enforcement Information Notice No. 82-29, "Control Rod Drive (CRD) Guide Tube Support Pin Failures at Westinghouse PWRs," July 23, 1982.**

**Available in NRC Public Document Room, 1717 H Street, NW., Washington, DC 20555, for inspection and copying (for a fee).

NRC FORM 335
(6-83)

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

1. REPORT NUMBER (Assigned by TIDC, add Vol. No., if any)
NUREG-0900
Vol. 7, No. 2

2. Leave blank

3. TITLE AND SUBTITLE
Report to Congress on Abnormal Occurrences
April - June 1984

4. RECIPIENT'S ACCESSION NUMBER

5. DATE REPORT COMPLETED

MONTH	YEAR
October	1984

6. AUTHOR(S)

7. DATE REPORT ISSUED

MONTH	YEAR
October	1984

8. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)
Office for Analysis and Evaluation of Operational Data
U.S. Nuclear Regulatory Commission
Washington, DC 20555

9. PROJECT/TASK/WORK UNIT NUMBER

10. FIN NUMBER

11. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)
Office for Analysis and Evaluation of Operational Data
U.S. Nuclear Regulatory Commission
Washington, DC 20555

12a. TYPE OF REPORT
Quarterly

12b. PERIOD COVERED (Inclusive dates)
April - June 1984

13. SUPPLEMENTARY NOTES

14. ABSTRACT (200 words or less)

Section 208 of the Energy Reorganization Act of 1974 identifies an abnormal occurrence as an unscheduled incident or event which the Nuclear Regulatory Commission determines to be significant from the standpoint of public health or safety and requires a quarterly report of such events to be made to Congress. This report covers the period April 1 to June 30, 1984.

During the report period, there was one abnormal occurrence at the nuclear power plants licensed by the NRC to operate; the event involved an inoperable containment spray system. There was one abnormal occurrence for the other NRC licensees; the event involved a therapeutic medical misadministration. There were no abnormal occurrences reported by the Agreement States.

The report also contains information updating some previously reported abnormal occurrences.

15a. KEY WORDS AND DOCUMENT ANALYSIS

15b. DESCRIPTORS

Containment Spray System; San Onofre Unit 3; Medical Institution; Therapeutic Medical Misadministration; Control Rod Drive Guide Tube Support Pin Failures; North Anna Unit 1; Point Beach Unit 1; Trojan; Main Generator Hydrogen Explosion and Fire; Rancho Seco; Loss of Non-Nuclear Instrumentation.

16. AVAILABILITY STATEMENT
Unlimited

17. SECURITY CLASSIFICATION (This report)
Unclassified

18. NUMBER OF PAGES

19. SECURITY CLASSIFICATION (This page)
Unclassified

20. PRICE
$

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

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

FOURTH CLASS MAIL
POSTAGE & FEES PAID
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PERMIT No. G-67

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