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SUBJECT: Forwards amend to FSAR for Nine Mile Point Unit 2.
Revised 6/21/89 (GD) and see Rept.
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NIAGARA MOHAWK

NIAGARA MOHAWK POWER CORPORATION/301 PLAINFIELD ROAD, SYRACUSE, N.Y. 13212/TELEPHONE (315) 474-1511

April 28, 1989
NMP2L 1198

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

Re: Nine Mile Point Unit 2
Docket No. 50-410
NPF-69

Gentlemen:

Pursuant to 10 CFR 50.4(b)(6) and 50.71(e), Niagara Mohawk Power Corporation hereby submits one signed original and ten copies of the Nine Mile Point Unit 2 Updated Final Safety Analysis Report, hereinafter referred to as the Updated Safety Analysis Report (USAR) for Nine Mile Point Unit 2. Copies are also being sent directly to the Regional Administrator, Region I and the NRC Resident Inspector at Nine Mile Point Unit 2. An extension for the submittal of the initial USAR (from October 1988 to April 1989) was requested by our September 16, 1988 letter and granted by the NRC on October 31, 1988. Under separate cover, we are transmitting updates to material which had previously been given proprietary status by the NRC pursuant to the provisions of 10 CFR 2.790.

In addition to plant modifications, the following changes have been incorporated into the initial Updated Safety Analysis Report:

1. The Emergency Plan, formerly included in the FSAR, is maintained in accordance with 10 CFR 50 Appendix E, V and therefore is not included in the USAR.

2. The Quality Assurance Program is maintained in accordance with 10 CFR 50.54(a)(3) and therefore is incorporated in the USAR (Chapter 17) by reference.

3. Appropriate portions of Niagara Mohawk's responses to NRC FSAR questions have been incorporated into the body of the initial USAR.

4. The Technical Specification has been referenced in place of Chapter 16 and the Chapter 16 text has been deleted from the USAR.

5. The initial USAR incorporates a number of editorial changes. These changes were to correct spelling and typographical errors; update references to USAR figures, sections, documents or tables of contents; to improve grammar or clarity; and to move information to more appropriate locations.

A053
1/10 Sets

The certification required by 10 CFR 50.71(e)(2) is attached to this letter. An errata sheet is provided in Attachment 1 describing corrections that were identified after the initial USAR was released for printing. Our Nuclear Compliance and Verification group is concluding its additional internal verification program on the submittal. Procedures are in place to document the results of the verification process. Any required correction will be made in the next update. In accordance with 10 CFR 50.71(e)(3)(i) and the NRC's exemption issued on October 31, 1988, the USAR is up-to-date as of April 30, 1988.

Attachment 2 is being submitted in fulfillment of the requirements of 10 CFR 50.71(e)(2)(ii) to identify changes made under the provisions of 10 CFR 50.59 but not previously submitted to the Commission. None of the safety evaluations in Attachment 2 involved an unreviewed safety question as defined by 10 CFR 50.59(a)(2). Pursuant to 10 CFR 50.59(b)(2), Niagara Mohawk had submitted on October 26, 1988 a summary of the safety evaluation reports. Attachment 2 supplements the previous submittal and also contains a list of safety evaluations that reflect changes in the design of the plant prior to the issuance of the full-term operating license.

Sincerely,

NIAGARA MOHAWK POWER CORPORATION

C. D. Terry
Vice President
Nuclear Engineering & Licensing

CDT/bd
7185G
xc: Regional Administrator, Region I
Mr. R. A. Capra, Director
Ms. M. L. Slosson, Project Manager
Mr. W. A. Cook, Resident Inspector
Records Management

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the Matter of)

NIAGARA MOHAWK POWER CORPORATION) Docket No. 50-410
(Nine Mile Point Nuclear Station)
Unit No. 2)

CERTIFICATION

C. D. Terry, being duly sworn, states that he is Vice President, Nuclear Engineering and Licensing of Niagara Mohawk Power Corporation, that he is authorized on the part of said Company to sign and file with the Nuclear Regulatory Commission this certification; and that, in accordance with 10 C.F.R. §50.71(e) (2), the information contained in the attached letter and updated Final Safety Analysis Report accurately presents changes made since the previous submittal necessary to reflect information and analyses submitted to the Commission or prepared pursuant to Commission requirement and contains an identification of changes made under the provisions of §50.59 but not previously submitted to the Commission.

By C. D. Terry
C. D. Terry
Vice President
Nuclear Engineering and Licensing

Subscribed and sworn to before me

this 28th day of April, 1989.

Diane R. Kimball
Notary Public
DIANE R. KIMBALL
Notary Public in the State of New York
Qualified in Onondaga County No. 4933503
My Commission Expires May 31, 1990

4252W

Volume

1

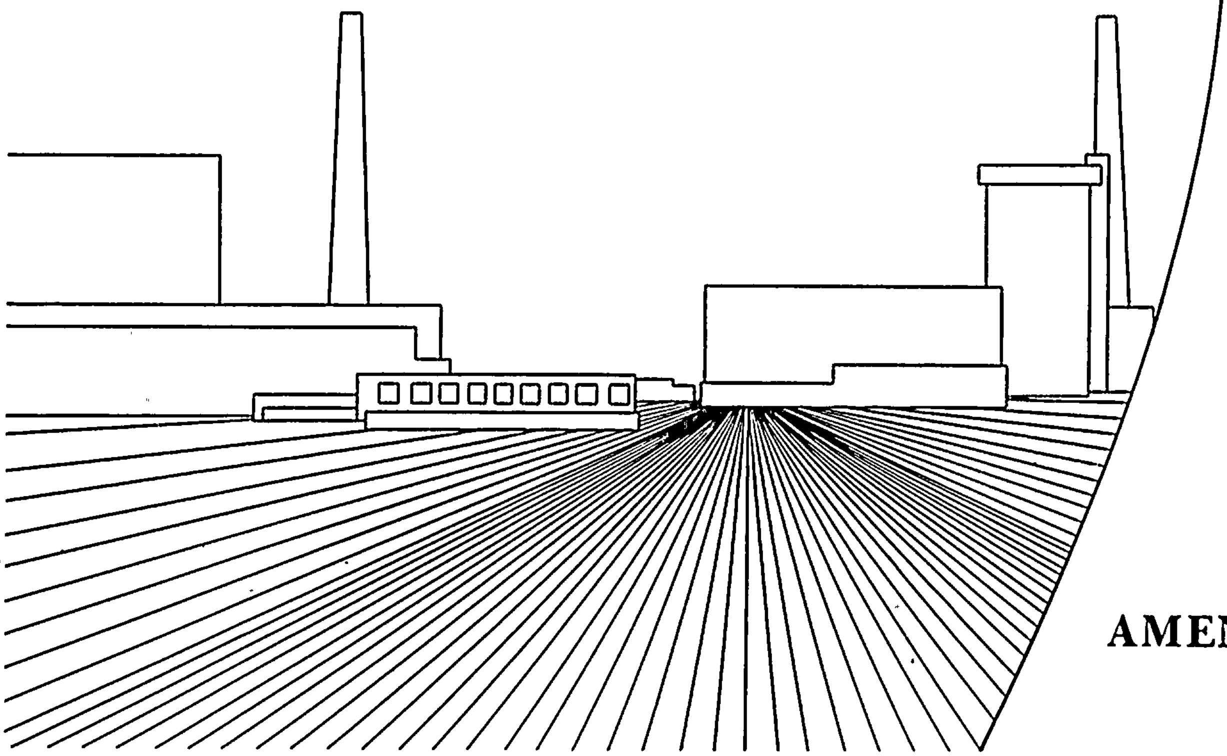
Superceded pss for
updated FSAR
50410
8905030108
4/28/89

THIS EROL SET HAS BEEN UPDATED TO INCLUDE REVISIONS THROUGH #27 (AMDT) DATED 7/24/86.

FINAL SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION – UNIT 2

NIAGARA MOHAWK



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CHAPTER 1

LIST OF FIGURES (Cont)

generator to the outgoing transmission system. The 115-kV switchyard receives power from two separate offsite power sources through two physically and electrically independent incoming circuits. The two circuits feed two separate reserve station service transformers and an auxiliary boiler transformer. The reserve station service transformers step down the offsite power from 115 to 13.8 and 4.16 kV, and provide two independent offsite power sources for the unit auxiliary power distribution system. The auxiliary boiler transformer steps down the offsite power from 115 to 13.8 and 4.16 kV. Its 13.8-kV winding supplies power to the auxiliary boiler and associated equipment; the 4.16-kV tertiary winding provides a backup source for the emergency 4.16-kV buses.

The unit auxiliary power distribution system feeds all unit auxiliary loads through 13.8-kV switchgear, 4.16-kV switchgear, 600-V load centers, 600-V motor control centers, and various ac and dc distribution panels. The system is divided into nuclear nonsafety-related and nuclear safety-related systems. The nuclear nonsafety-related auxiliary power distribution system feeds all non-Class 1E unit auxiliary loads. Under normal plant operating conditions, it is energized from the normal station service transformer. During startup and normal shutdown conditions, it is energized from offsite power sources through reserve station service transformers. A normal 125-V dc system, consisting of batteries, battery chargers, and distribution panels, provides a reliable source of power for protection, control, and instrumentation loads and dc motors under normal and emergency conditions of the plant. A ±24-V dc system provides a reliable source for the neutron monitoring system.

The nuclear safety-related auxiliary power distribution system supplies all Class 1E unit auxiliary loads. This system is divided into three independent divisions. Division I and Division II are independent redundant divisions and supply all nuclear safety-related auxiliary loads except the high pressure core spray (HPCS) system. The HPCS system and related equipment are supplied by Division III. All three divisions are normally energized from the offsite power sources through reserve station service transformers. The auxiliary boiler transformer can be connected manually to act as a backup source for either the Division I or Division II supply.

Each of the three divisions of the nuclear safety-related auxiliary power distribution systems has its own independent standby diesel generator. In the event of a LOCA and/or loss of offsite power, each division is energized from its own standby diesel generator. A 125-V emergency dc power system feeds all safety-related dc protection, control, and instrumentation loads and safety-related dc motors under normal operation of the plant as well as during emergency conditions. The system is divided into three independent divisions each consisting of its own battery, primary and backup battery chargers, switchgear, motor control centers, and distribution panels. Each division feeds the dc loads associated with the corresponding divisions of the nuclear safety-related auxiliary power distribution system.

Chapter 8 describes the electrical power system in detail.

1.2.5.2 Nuclear System Process Control and Instrumentation

Reactor Manual Control System

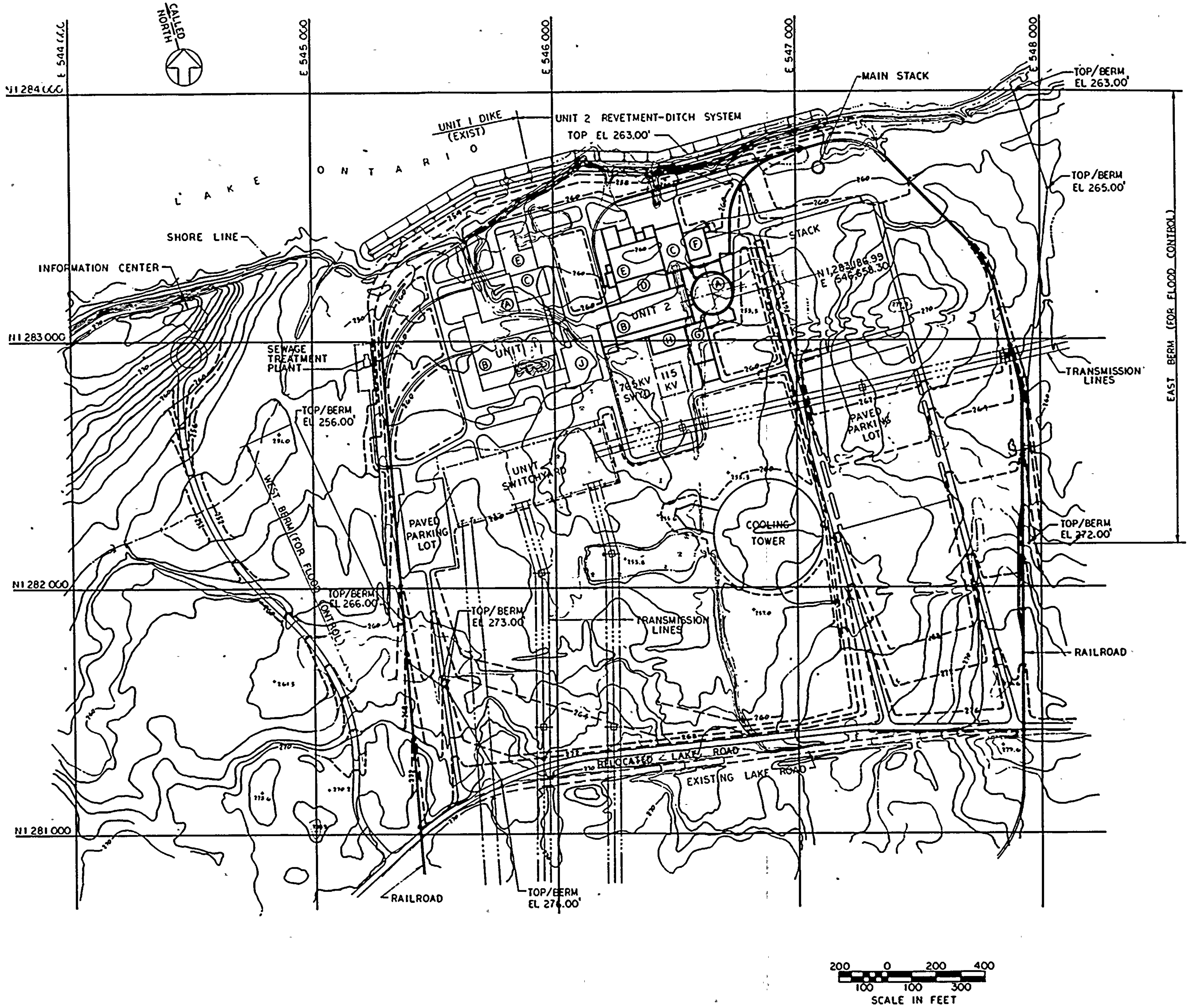
The reactor manual control system (RMCS) provides the means by which control rods are positioned from the control room for power control. The system operates valves in each hydraulic control unit to change control rod position. One control rod can be manipulated at a time. The RMCS includes the logic that restricts abnormal control rod movement (rod block) under certain conditions as a backup to procedural controls.

Recirculation Flow Control System

During normal power operation, a variable position discharge valve is used to control flow. Adjusting this valve changes the coolant flow rate through the core and thereby changes the core power level. The system can automatically adjust the reactor power to the load change by adjusting the electrical power supply.

Neutron Monitoring System

The neutron monitoring system (NMS) is a system of incore neutron detectors and out-of-core electronic monitoring equipment. The system provides indication of neutron flux, which can be correlated to thermal power level for the entire range of flux conditions that can exist in the core. The source range monitors (SRMs) and the intermediate range monitors (IRMs) provide flux level indications during reactor startup and low-power operation. The local power range monitors (LPRMs) and average power range monitors (APRMs) allow assessment of local and overall flux conditions during power range operation. The traversing incore probe (TIP) system provides a means to calibrate the



IDENTIFICATION LEGEND

- A REACTOR BUILDING
- B TURBINE BUILDING
- C RADWASTE BUILDING
- D HEATER BAYS
- E SCREENWELL BUILDING
- F CONDENSATE STORAGE TANK BLDG
- G CONTROL BUILDING
- H NORMAL SWITCHGEAR BUILDING
- J ADMINISTRATION BUILDING

LEGEND

- ORIGINAL GROUND CONTOUR
- NEW GROUND CONTOUR
- FENCE LINE

NOTES

1. GRID COORDINATES REFER TO NEW YORK STATE COORDINATE SYSTEM
2. ELEVATIONS REFER TO MEAN SEA LEVEL
3. ORIGINAL CONTOUR INTERVAL - 2 FEET

FIGURE 1.2-1

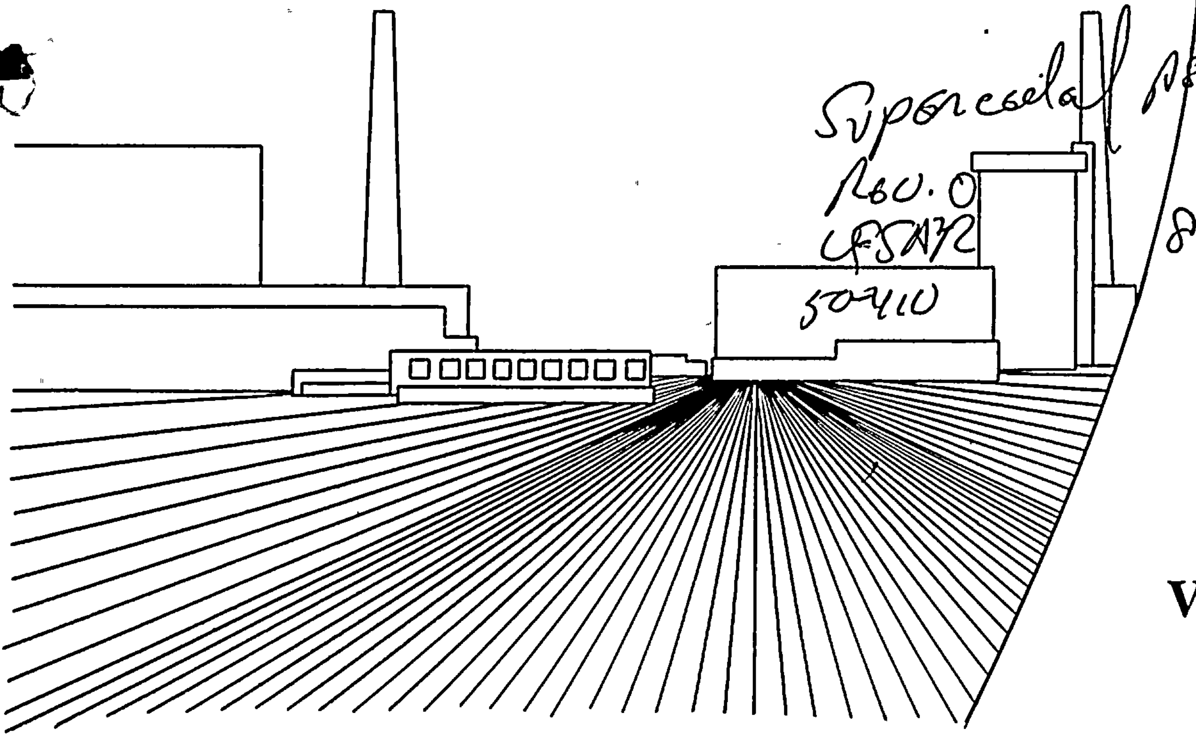
PLOT PLAN

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
FINAL SAFETY ANALYSIS REPORT

FINAL SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION — UNIT 2

NIAGARA MOHAWK



Superceded per Rev. 0 UFSAR 50410

8905030108

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TABLE 1.8-1 (Cont)

Regulatory Guide 1.28, Revision 2 (February 1979)

Quality Assurance Program Requirements
(Design and Construction)

FSAR Section Chapter 17, QA Topical Report QATR-1, Rev. 1 26

Position* 26

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

*This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR-1, Revision 1 supersedes this commitment. 26

TABLE 1.8-1 (Cont)

Regulatory Guide 1.30, Revision 0 (August 1972)

Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment

FSAR Sections 3.11 and 7.2, Chapter 17, QA Topical Report QATR-1, Rev. 1 26

Position*

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

The Unit 2 quality assurance program complies with Regulatory Guide 1.30 as described in Appendix VII of the Quality Assurance Manual for the project during construction. Unit 2 also complies with this regulatory guide as described in Chapter 17 of the FSAR.

Regulatory Guide 1.30, Rev. 0, endorses IEEE Standard 336-1971. Unit 2 Specification E061A, Electrical Installation, invokes IEEE Standard 336-1977, which is more conservative than IEEE Standard 336-1971.

Section 3 of IEEE-336 addresses the requirements for preinstallation verification of material and equipment. It also states that "it is not intended to duplicate inspections but rather to verify that items are in satisfactory condition for installation." Preinstallation verification includes the following:

1. Identification of materials and equipment.

2. Availability of procedures, instruction manuals, and special work instructions.

3. Review of records of storage and preventive maintenance measures.

4. Visual examination of materials and equipment to ensure physical integrity.

All these required verifications are addressed by the SWEC QA program for receipt, storage, and preventive maintenance inspections. These inspections meet the intent of IEEE-336,

TABLE 1.8-1 (Cont)

Regulatory Guide 1.30, Revision 0 (August 1972)

Section 3; therefore, additional preinstallation verification is not done for the following components and materials (all equipment, however, is subject to preinstallation verification):

1. Balance-of-plant electrical components and materials such as terminal blocks, fuses, connectors, lugs, mounting hardware, etc.

2. PGCC electrical components and materials that are shipped separately from the main panels by GE, e.g., relays, meters, switches, connectors, lugs, mounting hardware, etc.

The above components and materials are subject to inprocess installation inspection and final installation inspections.

---

*This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR-1, Revision 1 supersedes this commitment. 26

TABLE 1.8-1 (Cont)

Regulatory Guide 1.37, Revision 0 (March 16, 1973)

Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants

FSAR Sections 4.5.1.4, 4.5.2.4, 6.1.1, and 17.2, QA Topical Report QATR-1, Rev. 1 26

Position*

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below.

1. Paragraph C.3 The water quality for final flushes of fluid systems and associated components is at least equivalent to the quality of the operating system water, except for the oxygen content.

2. Paragraph C.4 Expendable materials, i.e., inks and related products, temperature indicating sticks, tapes, gummed labels, wrapping materials (other than polyethylene), water soluble dam materials, lubricants, NDT penetrant materials, and couplants that contact stainless steel or nickel alloy surfaces are in accordance with the Unit 2 Position for Regulatory Guide 1.38, Revision 2.

3. Due to seasonal conditions, freshwater from Lake Ontario will have an allowable upper pH limit of 8.5.

4. Upgraded piping systems and components constructed of carbon steel materials will meet Class B cleanness requirements except for final flushing/cleaning which may exhibit rust staining in accordance with Class C cleanness requirements.

The quality assurance requirements of Regulatory Guide 1.37 have been addressed in Appendix VII of the Quality Assurance Program Manual and Section 17 for the Unit 2 project.

TABLE 1.8-1 (Cont)

Erection specifications and procedures for Category I fluid systems and associated components include the requirements of the guide as delineated above.

*This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR-1, Revision 1 supersedes this commitment. 26

TABLE 1.8-1 (Cont)

Regulatory Guide 1.38, Revision 2 (May 1977)

Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants

FSAR Section Chapter 17, QA Topical Report QATR-1, Rev. 1 26

Position* 26

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

SWEC and NMPC QA program satisfies the QA requirements of Regulatory Guide 1.38 (Unit 2 QA Program Manual Appendix VII and Section 17).

---

*This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR-1, Revision 1 supersedes this commitment. 26

TABLE 1.8-1 (Cont)

Regulatory Guide 1.39, Revision 2 (September 1977)

Housekeeping Requirements for Water-Cooled Nuclear Power Plants

FSAR Section Chapter 17, QA Topical Report QATR-1, Rev. 1 26

Position* 26

The Unit 2 project complies with the requirements of the Regulatory Position (Paragraph C) of this guide.

Erection and installation specifications establish the requirements and the QA provisions to ensure compliance with this guide. Additionally, the requirements are implemented by site administrative procedures.

*This commitment is modified at the time of the QA Topical Report implementation. At that time the QATR-1, Revision 1 supersedes this commitment. 26

TABLE 1.8-1 (Cont)

Regulatory Guide 1.52, Revision 2 (March 1978) (Cont)

ERDA 76-21, except for the frame tolerance guidelines in Table 4.2. The tolerances selected for HEPA and adsorber mountings are sufficient to satisfy the bank leak test criteria of Paragraphs C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2.

8. Paragraph C.3.h Exception is taken to the recommendations of Section 4.5.8 of ERDA 76-21 relative to drain sizes and arrangement. Normally open manual valves, in addition to water seals and

TABLE 1.8-1 (Cont)

Regulatory Guide 1.52, Revision 2 (March 1978) (Cont)

traps, will be provided to control the discharge of the fire sprinkler flow.

9. Paragraph C.3.i Exception is taken to the requirement that the absorption unit should be designed for a maximum loading of 2.5 mg of total iodine per gram of activated carbon. Regulatory Guide 1.52, Revision 1, states that "the absorption unit should have the capacity of loading 2.5 mg of total iodine (radioactive plus stable) per gram of activated carbon." The absorption unit provided has a loading capacity of 10.0 mg of total iodine per gram of activated carbon.

10. Paragraph C.3.k Exception is taken to the requirement for humidity control to below 70 percent relative humidity for low flow air bleed cooling.

    A clarification is provided to the requirement that the low air bleed cooling to mitigate iodine desorption and auto-ignition. Each filter train is physically separated, and the common connection between the filter trains is provided with redundant high temperature sensors and isolation valves to maintain equipment integrity in one filter train upon detection of high temperature. 18

11. Paragraph C.3.1 System resistances will be determined in accordance with Section 5.7.1 of ANSI N509-1976 except that fan inlet and outlet losses will not be calculated in accordance with AMCA 201, but will be estimated and documented accordingly.

    Exception is taken to balancing techniques defined in Section 5.7.3 of ANSI N509-1976. The acceptable amplitude of vibration, peak to peak, in any plane measured on the shaft adjacent to the bearings, corresponds to a vibration velocity of 0.1 in./sec at the rated speed using the displacement values given in AMCA Publication 801. The displacement criteria using maximum vibration velocity method in accordance with ANSI N509-1976 are not required by

TABLE 1.8-1 (CONT)

Regulatory Guide 1.58, Revision 1 (September 1980) (Cont)

Qualification of Nuclear Power Plant
Inspection, Examination, and Testing Personnel

FSAR Section 2.4

Position

The Unit 2 project complies with the Regulatory Postion (Paragraph C) of this guide through the alternate approaches described below and in Chapter 14. | 22

BOP

The quality assurance program for Unit 2 is currently in compliance with Regulatory Positions C.5, 7, 8, and 10 of this regulatory guide. Regarding Regulatory Position C.6 of this regulatory guide and Section 3.5, Education and Experience Recommendations, of ANSI N45.2.6-1978, the following alternatives are proposed for personnel education and experience for each level:

3.5.1 Level I

1. Two years of related experience in equivalent inspection, examination, or testing activities, or

2. High school graduation/general education development (GED) equivalent and 6 months of related experience in equivalent inspection, examination, or testing activities, or

3. Completion of college-level work leading to an associate degree in a related discipline plus 3 months of related experience in equivalent inspection, examination, or testing activities.

4. Four-year college graduate plus 1 month of related experience or equivalent inspection, examination, or testing activities.

TABLE 1.8-1 (Cont)

Regulatory Guide 1.75, Revision 2 (September 1978)

Physical Independence of Electric Systems

FSAR Sections 7.1.2, 7.6.2, 8.3.1

Position

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below and in Section 7.6.2 and 8.3.1.

Regulatory Position C.1 states that "interrupting devices actuated only by fault current are not considered to be isolation devices within the context of this document." In the case of control and instrument circuits, a combination of two interrupting devices actuated by fault current have been used to isolate nonClass 1E circuits from Class 1E circuits. Both of these devices are Class 1E, and both of them are coordinated with the main breaker upstream so that a failure of a nonClass 1E device or circuit will not affect any Class 1E device or system. Any circuit breakers associated with this redundant protection will be tested during each refueling outage.

Regulatory Position C.9 requires that cable splices in raceways be prohibited. Splicing in electrical penetrations for termination is considered to be exempt from this requirement.

Regulatory Position C.10 requires that the cables be marked at 5-ft intervals. This is a typographical error as confirmed by the former Electrical, Instrument and Control Branch Chief of USNRC, T. A. Ippolito, on October 10, 1975, and the NRC Power Systems Branch Section Leader, R. G. FitzPatrick, on October 30, 1980. The correct distance is 15 ft, which has been followed in Unit 2.

The minimum separation distance from 600 V or less nonsafety-related conduit to safety-related open cable trays and cable in free air for any service level is 1 in. 26

All cables used in Unit 2 are flame-retardant. The cable trays are not filled above the side rails. The hazard, in this case, is limited to failure or faults internal to the nonsafety cables in rigid steel conduit. Unit 2 has determined by analysis that 1-in separation between the Class 1E cable tray and nonClass 1E conduit provides adequate protection for the Class 1E cables in the open ladder tray in the

TABLE 1.8-1 (Cont)

event of any failure of the nonClass 1E cables in conduit. This has been established by tests with 600 V levels, as explained later in this section. 26

Aluminum sheath cables (ALS) used for low energy 120-V ac systems and 8-hr battery pack lighting systems, are considered enclosed raceways. These cables have flame retardant cross-linked polyethylene insulation, chlorosulphonated polyethylene jacket, and polypropylene fillers enclosed in a continuous, impervious aluminum sheath which provides adequate protection. As such, the minimum separation between these cables and Class 1E raceways is 1 in.

The minimum separation between any Class 1E raceway and any lighting cord for drops to the lighting fixtures shall be 1 in. These cords are of size 12 AWG and supply 120/208 V ac low energy in low density applications. As such, 1-in separation provides adequate protection to the Class 1E circuits in the event of a fault in any lighting cord.

IEEE Standard 384-1974, Section 5.1.1.2, allows lesser separation distances than those specified in Sections 5.1.3 and 5.1.4, if established by analysis. Various tests have indicated that the following minimum separation distances between redundant Class 1E cables and raceways, or between Class 1E and nonClass 1E cables and raceways, 600 V level and below, should be adequate to maintain independence of the redundant systems. NMPC also has verified these minimum separation distances by plant specific tests (Wyle Test Report No. 47906-02, Electrical Separation Verification Testing).

Cable tray to cable tray	10 in horizontal or 10 in vertical
Cable tray to conduit	1 in
Cable in free air to conduit	1/2 in
Cable in free air to cable in free air	10 in vertical or 10 in horizontal
Cable in free air to cable tray	10 in vertical or 10 in horizontal
Wrapped cable to unwrapped cable	0 in
Conduit to conduit	1/2 in

TABLE 1.8-1 (Cont)

Class 1E control/instrument cable to nonClass 1E control instrument cable inside control/instrument cabinets	1 in

Where the minimum separation distances specified in Sections 5.1.3 and 5.1.4 of IEEE Standard 384-1974 cannot be maintained due to physical arrangements, the minimum separation distances specified above shall be maintained.

Where the minimum separation distances specified in this section cannot be maintained, enclosed raceways will be used; or a separation barrier will be installed.

TABLE 1.8-1 (Cont)

Regulatory Guide 22 (July 1984) | 18

Materials Code Case Acceptability -
ASME Section III Division I

FSAR Section 5.2.1.2

Position

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approaches described below.

Regulatory Guide 1.85 provides a list of ASME design and fabrication code cases that have been generically approved by the regulatory staff. Code cases on this list may, for design purposes, be used until appropriately annulled. Annulled cases are considered "active" for equipment that has been contractually committed to fabrication prior to the annulment.

The various ASME code cases that applied to components in the RCPB are listed in Table 5.2-1.

All Safety Class 2 and 3 equipment has been designed to ASME code or ASME-approved code cases. This provision, together with the quality control programs, provides adequate safety equipment functional assurances.

TABLE 1.8-1 (Cont)

Regulatory Guide 1.88, Revision 2 (October 1976)

Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records

FSAR Section Chapter 17, QA Topical Report QATR-1, Rev. 1 | 26

Position* | 26

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide, except to change ANSI N45.2.9-1974 Section 5.6, Paragraph 3 to "Two hour minimum rated facility" in accordance with NFPA 232-1980. Implementation is as described below.

Unit 2 Quality Assurance Records (and other required records) are stored in facilities designated as the Permanent Plant File and the Records Acceptance Center. In-process records are stored in controlled Intermediate Storage Facilities. Specific requirements for each include:

1. Permanent Plant File - Complies to the above paragraph of this position statement.

2. Records Acceptance Center - Complies with ANSI N45.2.9-1974, Section 5.3 to provide a mechanism to control records. The storage facility shall meet Section 5.6, except as follows:

   a. Structure has a minimum 2-hr fire rating.

   b. Doors, frames, and hardware have a 2-hr vault door.

   c. Electrical facilities shall be limited to ceiling lights, air-conditioning units, smoke detectors, and alarm circuits.

3. Intermediate Storage Facilities - Complies with ANSI N45.2.9-1974, Section 5.3 to provide a mechanism to control records. Each intermediate storage facility shall be evaluated by a Fire Protection Engineer to fulfill NFPA 232-1980 requirements. NOTE: All intermediate storage facilities will be eliminated as contractor work is concluded.

TABLE 1.8-1 (Cont)

The above controls and facilities are prepared to protect Quality Assurance records which take their physical form as radiographs, microfilm and paper.

1. Special handling and environmental storage considerations must be maintained for radiographs.

2. Designated archive (silver halide only) microfilm requires environmental storage considerations.

3. Use of fire-retardant cabinets is applicable to paper storage only.

Technical Justification

ANSI N45.2.9-1974 does not adequately define the storage facilities for inprocess quality records or NFPA requirements for fire rating of the facility. NFPA 232-1980, 1-3, emphasizes, "To consult with an experienced and competent Fire Protection Engineer or Records Protection Consultant." This position is based upon his recommendations. The Unit 2 Records Management Plan establishes the program for turnover, collection, review, transfer, receipt, verification, permanent plant file entry, and retention of all Unit 2 records with implementing policy guidelines which specify the facility types.

*This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR-1, Revision 1, supersedes this commitment. 26

TABLE 1.8-1 (Cont)

Regulatory Guide 1.94, Revision 1 (April 1976)

Quality Assurance Requirements For Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants

FSAR Section Chapter 17, QA Topical Report QATR-1, Rev. 1 26

Position*

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

1. ANSI N45.2.5-1974 Section 5.3 Bolt holes generally will not be burned (oxygen cut). If holes must be burned, the following criteria will be followed: a) after cutting, the edges of the cut will be ground or reamed back a minimum of 1/32 in, and b) the final bolt hole dimensions will not exceed those given in the Specification for Structural Joints Using ASTM A325 or A490 bolts.

2. ANSI N45.2.5-1974 Section 5.4 For the Unit 2 project, the criterion established for correct bolt length is one thread extending beyond the face of the nut.

3. ANSI N45.2.5-1974 Section 5.5 All reinforcing bar splices made by arc welding, except those splices welded to metal embedments, will be selected on a random basis for radiography as specified in the Unit 2-PSAR, Section 12.6.3, and inspected in accordance with AWS D12.1. Splices welded to metal embedments will be inspected in accordance with AWS 12.1. Additionally, sister splice testing will be done in accordance with Specification No. NMP2-S203C with the same frequency as specified for B-series sister splices when required by the engineers.

4. ANSI N45.2.5-1974 Section 6.2.2 Exceptions regarding mechanical splicing of QA Category I rein-

TABLE 1.8-1 (Cont)

forcing bars can be found in Unit 2 Project Position 1.10.

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*This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR-1, Revision 1 supersedes this commitment. 26

TABLE 1.8-1 (Cont)

Regulatory Guide 1.97, Revision 2 (December 1980)

Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident

FSAR Section 7.1.2

Position

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

Type A 1. Conformance is in accordance with BWR Owners Group report position on NRC Regulatory Guide 1.97, Revision 2, dated May 1982 (see response to Question F421.36). 19

Type B 1. Neutron flux - Conformance is in accordance with BWR Owners Group report position on NRC Regulatory Guide 1.97, Revision 2, dated May 1982 (see response to Question F421.36). 19

2. Core thermocouples (also incorporates Type C) - See TMI Item II.F.1 in Section 1.10 (see response to Question F421.36). 19

Type C 1. Drywell drain sumps level - See TMI Item II F.1 in Section 1.10 (see response to Question F421.36). 19

Type D 1. Suppression pool temperature - Meets intent of guide. See TMI Item II F.1 in Section 1.10 (see response to Question F421.36). 19

2. Drywell atmosphere temperature - Meets intent of guide. See TMI Item II F.1 in Section 1.10 (see response to Question F421.36). 19

3. Cooling water temperature to ESF components - Meets intent of guide. See TMI Item II F.1 in Section 1.10 (see response to Question F421.36). 19

TABLE 1.8-1 (Cont)

Regulatory Guide 1.116, Revision O-R (May 1977)

Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems

FSAR Section Chapter 17, QA Topical Report QATR-1, Rev. 1 26

Position* 26

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide.

*This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR-1, Revision 1 supersedes this commitment. 26

TABLE 1.8-1 (Cont)

Regulatory Guide 1.123, Revision 1 (July 1977)

Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants

FSAR Section Chapter 17, QA Topical Report QATR-1, Rev. 1 | 26

Position* | 26

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described as follows:

> Certain standard catalog or nonengineered items may be processed without seller prequalification. This alternative method is described in Section 7, paragraphs 1.4.1, 1.4.2, 1.4.3, and 3.1.2 of the Quality Assurance Program for Unit 2.

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*This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR-1, Revision 1 supersedes this commitment. | 26

TABLE 1.8-1 (Cont)

Regulatory Guide 1.143, Revision 1 (October 1979)

Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants

FSAR Section 15.7.1, 11.4

Position

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

A. Liquid Waste System

The fiberglass tanks purchased for the liquid radwaste system (LWS) have been designed in accordance with the National Bureau of Standards (NBS) Product Standard (PS) PS 15-69, Custom Contact-Molded Reinforced-Polyester Chemical-Resistant Process Equipment, as identified in NMP2 Preliminary Safety Analysis Report, Table C-10b.

NBS PS 15-69 provides the necessary design and fabrication requirements to ensure the integrity of the tanks without the additional cost of burst testing.

B. Off-Gas System

The charcoal adsorbers of the off-gas system are not designed to the seismic requirements of this regulatory guide.

Offsite dose calculations in accordance with Chapter 15.7.1 of the NMP2 FSAR show that release of gaseous activity due to failure of the charcoal adsorbers results in offsite doses less than 0.5 Rem to the whole body. In accordance with Regulatory Guide 1.29, this permits classification as nonseismic. At the time of design and procurement of the off-gas system (July 1974), Regulatory Guide 1.29, Revision 1, established the seismic requirements for the radioactive waste processing systems.

TABLE 1.8-1 (Cont)

Regulatory Guide 1.144, Revision 1 (September 1980)

Auditing of Quality Assurance Programs
for Nuclear Power Plants

FSAR Section Chapter 17, QA Topical Report QATR-1, Rev. 1 | 26

Position* | 26

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

The pre-audit and post-audit conferences required by Sections 4.3.1 and 4.3.3 of ANSI N45.2.12-1977 may be fulfilled by a variety of communications such as telephone conversations.

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*This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR-1, Revision 1 supersedes this commitment. | 26

TABLE 1.8-1 (Cont)

Regulatory Guide 1.146, Revision 0 (August 1980)

Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

FSAR Section Chapter 17, QA Topical Report QATR-1, Rev. 1 26

Position*

The Unit 2 project complies with Regulatory Position (Paragraph C) of this guide.

*This commitment is modified at the time of the QA Topical Report implementation. At that time, the QATR-1, Revision 1 supersedes this commitment. 26

TABLE 1.8-1 (Cont)

Regulatory Guide 1.147, Revision 1 (February 1982)

Inservice Inspection Code Case Acceptability -
ASME Section XI Division 1

FSAR Section 14

Position

The Unit 2 project complies with the Regulatory Position (Paragraph C) of this guide through the alternate approach described below.

At the date of issuance of the NMP2 construction permit, the 1974 edition of ASME Section XI was in effect. The NMP2 ISI is based upon this edition according to 10CFR50.55a(g)(2).

TABLE 1.8-1 (Cont)

Regulatory Guide 1.150, Revision 1 (February 1983) 23

Ultrasonic Testing of Reactor Vessel Welds
During Preservice and Inservice Examination

FSAR Section PSI/ISI Plan 23

Position

The Unit 2 degree of compliance with the Regulatory Position (Paragraph C and Appendix A) of this guide is addressed in the response to Question F250.1. 23

TABLE 1.9-1 (Cont)

SRP Number	Title	Revision	Conformance	Difference
6.2.1.4	Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures	1	NA	NA
6.2.1.5	Minimum Containment Pressure Analysis for Emergency Core Cooling System Performance Capability Studies	2	NA	NA
6.2.2	Containment Heat Removal Systems	3		Attachment 1.9-45
6.2.3	Secondary Containment Functional Design	2		Attachment 1.9-46
6.2.4	Containment Isolation System	2	X		23
6.2.5	Combustible Gas Control in Containment	2	X	
	Appendix A	2	NA	NA
	BTP CSB 6-2	2	NA	NA
6.2.6	Containment Leakage Testing	2	X	
6.2.7	Fracture Prevention of Containment Pressure Boundary	0		Attachment 1.9-48
6.3	Emergency Core Cooling System			Attachment 1.9-49
	BTP RSB 6-1	1	NA	NA
6.4	Control Room Habitability System	2	X	
	Appendix A	2	X	
6.5.1	Engineered Safety Feature Atmosphere Cleanup Systems	2		Attachment 1.9-50
6.5.2	Containment Spray as a Fission Product Cleanup System	1	NA	NA
6.5.3	Fission Product Control Systems and Structures	2	X	
6.5.4	Ice Condenser as a Fission Product Cleanup System	2	NA	NA
6.6	Inservice Inspection of Class 2 and 3 Components	1	X	
6.7	Main Steam Isolation Valve Leakage Control System (BWR)	2	NA	NA
CHAPTER 7: INSTRUMENTATION AND CONTROLS				
7.1	Instrumentation and Controls - Introduction	2	X	
	Table 7-1 - Acceptance Criteria and Guidelines for Instrumentation and Controls Systems Important To Safety	2	X	
7.2	Reactor Trip System	2	X	
	Appendix A	2	NA	NA
7.3	Engineered Safety Features System	2	X	
	Appendix A	2	NA	NA
7.4	Safe Shutdown Systems	2	X	
7.5	Information Systems Important to Safety	2	X	

ATTACHMENT 1.9-14 (Cont)

containment. This is verified in the jet impingement evaluation where breaks are postulated at various elevations and azimuths. Additional investigation is only repetitive. It is therefore concluded that this will not degrade the safety of the plant.

Difference 2

Section B.1.c.1.d states that "if intermediate break locations cannot be determined by (b), (B.1.c.1.b) and (c), (B.1.c.1.c) above, two highest stress locations based on equation (10) should be selected." Unit 2 uses a reasonable basis which includes factors such as points of maximum stress intensity and/or cumulative usage factors; however, the points of maximum stress intensity are based on Equation (12) or (13).

Discussion Since all postulated intermediate breaks require evaluation of Equations (12) and (13) and cumulative usage factors, it is reasonable to use these equations to determine points of maximum stress intensity. This approach is conservative. 1

Difference 3

Section B.1.c.4 states that "if a structure separates a high energy line from an essential component, the separating structure should be designed to withstand the consequences of the pipe break in the high energy line which produces the greatest effect at the structure irrespective of the fact that the above criteria might not require such a break location to be postulated." Unit 2 design structures withstand the consequence of pipe breaks postulated at locations in accordance with Sections B.1.c.1, B.1.c.2, and B.1.c.3.

Discussion A systematic logical method must be used to evaluate the effects of pipe breaks in order to address a finite number of potential load cases. By assuming breaks at highly stressed locations and by requiring a minimum number of locations to be selected, a reasonable margin of safety will evolve.

Requiring breaks to be postulated based on structural capability is not prudent and does not enhance the safety of the plant. Several points are:

ATTACHMENT 1.9-14 (Cont)

1. Pipe whip loadings are very sensitive to the distance over which unrestrained whip could occur, piping geometry, and break orientation. An infinite number of cases would require consideration particularly if splits are arbitrarily postulated along the length of the pipe. Jet impingement does not have this problem since the load is distributed over a reasonable area. However, pipe whip requires evaluation of local effects, which is much more involved.

1 2. An excessive number of scab plates would be required on all structures which separate high energy and essential systems, thus causing an unreasonable number of scab plates to be installed.

3. By strengthening the weakest part of a structure, the next weakest part would then be the worst case. This is a perpetual cycle.

4. Additional safety is not really obtained by evaluating the least likely events. Since pipe breaks themselves are extremely unlikely, it is reasonable to postulate them only at the higher stressed locations. Additionally, all walls in the proximity of high energy systems are evaluated for a reasonable number of pipe breaks simply due to the number of breaks which must be postulated using the stress criteria.

ATTACHMENT 1.9-29

STANDARD REVIEW PLAN 3.11, REVISION 2
ENVIRONMENTAL QUALIFICATION OF MECHANICAL AND ELECTRICAL EQUIPMENT

Difference 1

The submittal of the environmental qualification document which demonstrates equipment environmental capability is not included.

Discussion The environmental qualification document will be submitted and the FSAR amended accordingly prior to fuel load.

Difference 2

Discussion of equipment qualification to a mild environment is not included. 1

Discussion Definitive guidelines are not yet available from the NRC concerning equipment qualification in mild environment.

Difference 3

Coverage of mechanical equipment qualification is not included.

Discussion Current NRC direction indicates that formal mechanical equipment qualification guidelines may be issued in the future. The NRC has stated that no further requests for mechanical equipment qualification data will be made until the NRC has acceptance criteria upon which to evaluate them. When NRC guidelines are issued, the mechanical equipment qualification impact will be addressed.

ATTACHMENT 1.9-61

STANDARD REVIEW PLAN 9.5.1, REVISION 3, JULY 1981
FIRE PROTECTION PROGRAM (FIRE PROTECTION SYSTEM)

Deviations to BTP CMEB 9.5-1
Attached to Standard Review Plan 9.5.1
<u>Fire Protection Program</u>
<u>Difference 1</u>

Section C.1.c.(3) states that "the fire suppression system should be capable of delivering water to manual hose stations located within hose reach of areas containing equipment required for safe shutdown following the safe shutdown earthquake (SSE)."

<u>Discussion</u> Unit 2 standpipe and hose connection design is in accordance with Appendix A (dated August 1976) to BTP 9.5-1 (dated May 1, 1976) and Appendix R to 10CFR50, and is not seismically qualified.

The design does not contemplate simultaneous earthquake and fire conditions; therefore, this requirement was not incorporated into the design. Further, justification is that Unit 2 is not in an area of high seismic activity.

<u>Difference 2</u>

Section C.5.a(3)(b) of Unit 2 design incorporates fire boot-type penetration seals (approximately 200 of 11,000 fire rated seals) for which temperature levels on the unexposed side reached 393°F during the acceptance test. 27

<u>Discussion</u> Fixed combustibles potentially within close proximity have ignition temperatures of >500°F. Cables are generally installed in raceways (i.e., conduit or cable trays).

<u>Difference 3</u> 27

Section C.5.a(5) - Unit 2 fire doors, including fire doors in areas protected by automatic total flooding gas suppression systems, are administratively supervised to verify that they are in the closed position.

<u>Discussion</u> Fire doors are maintained in the closed position. Additionally, fire doors in areas protected by automatic total flooding CO_2^- systems are provided with CO_2 activated door releases, in the event that the door is in

ATTACHMENT 1.9-61 (Cont)

the open position at the time of CO_2 discharge. Halon 1301 suppression systems are used in computer rooms and control rooms. Doors to these areas are inherently supervised by the occupants in the area, in addition to the daily inspection, to verify that the doors are in the proper position.

ATTACHMENT 1.9-61 (Cont)

incorporate the use of open directional spray nozzles discharge an excessive amount of water in protected areas, requiring substantially larger drainage and processing capabilities than areas protected by sprinkler systems which minimize the potential for damage to safety-related structures and components.

<u>Difference 7</u> 27

Section C.5.g.(1) - Unit 2 emergency lighting capability is provided by means other than individual 8-hr battery supplies.

<u>Discussion</u> Areas which must be manned during safe shutdown will be supplied with 8-hr battery packs for access and egress lighting.

<u>Difference 8</u> 27

Section C.5.g.(3) - The Unit 2 emergency communications system is not independent of the plant communication system.

<u>Discussion</u>

Fixed emergency communications systems independent of normal plant communications systems are not necessary because:

1. The systems are connectible to uninterruptible power sources, which provide reliability during emergency conditions.

2. In case of total loss of power to all communication systems, the Sound Powered Communication (SPC) system can be utilized.

3. The system is set up as described in Section 9.5.2.

4. The system and important components are supervised.

<u>Difference 9</u> 27

Section C.6.a.(3) - The fire detector spacing criteria for Unit 2 meet the intent of NFPA 72E.

<u>Discussion</u> NFPA 72E recommends one detector per bay for beam depth greater than 8 in and bay width <u>greater</u> than

ATTACHMENT 1.9-61 (Cont)

8 ft. NFPA 72E does not address beam depth greater than 8 in and bay width less than 8 ft. In this situation, the Unit 2 design incorporates one detector for every other bay mounted on the bottom flange of structural steel.

Difference 10 | 27

Section C.6.c.(4) - Unit 2 design does not incorporate a cross connection to the service water system for firefighting capability post-SSE.

Discussion Standpipes and hose connections for manual fire fighting are seismically supported in safety-related areas and in areas containing safety-related equipment. The design bases do not contemplate simultaneous earthquake and fire conditions; therefore, this requirement was not incorporated into the design. Further justification is that Unit 2 is not in an area of high seismic activity.

Difference 11 | 27

Section C.7.a.(1), part (c) - During normal operation, the Unit 2 design does not incorporate the use of general area fire detection in the primary containment.

Discussion The Unit 2 containment is inerted during normal operation.

Difference 12 | 27

In general, Section C endorses the use of the National Fire Protection Association (NFPA) standards. Unit 2 deviates from a number of these NFPA standards.

Discussion Each Unit 2 deviation to the NFPA standards is described and justified in Table 9.5-3.

ATTACHMENT 1.9-80

SRP DEVIATION WRITEUPS
CHAPTER 16 - TECHNICAL SPECIFICATIONS 1

The information contained in Chapter 16 is preliminary and has not yet been modified to reflect NMPC policy and Unit 2 design. Therefore, an analysis to determine conformance to the SRP is not yet required.

NUREG-0578 Position (Position No.)	Clarification
SRO training (3)	Specified in ANS 3.1 (Draft) Section 5.2.1.8
Administrative duties (4)	Not affecting plant safety
Administrative duties reviewed (4)*	On same interval as reinforcement: i.e., annual by V. P. for operations

Nine Mile Point Unit 2 Position

Prior to fuel loading and annually thereafter, the Vice President Nuclear Generation shall issue a management directive that emphasizes the primary management responsibility of the Station Shift Supervisor (SSS) for safe operation of the plant under all conditions on his shift and clearly establishes his command duties.

Plant procedures are written to ensure that the duties, responsibilities, and authority of the SSS and other licensed control room operators are properly defined to affect the chain of command. 14

In the future, administrative duties of the SSS will be reviewed annually after fuel load by the Vice President Nuclear Generation to ensure that such functions do not detract from safe plant operation.

SSS Responsibilities

The Station Shift Supervisor is in charge of all operations on his assigned shift. Under the general direction of the Supervisor Operations Nuclear, his function includes direction of shift activities, authorization of equipment releases for maintenance, ensuring that the plant is operated safely and within the license and technical specifications and ensuring that plant operations are conducted in accordance with approved procedures. As

*This requirement shall be met before fuel loading. See NUREG-0578, Section 22.1a, Item 4 and NRC letters of September 27, and November 9, 1979.

17 overall supervisor of operations for his shift, the Shift Supervisor should avoid becoming personally involved in the manipulative tasks or details of operation of any one portion of the plant so that he may retain a comprehensive perspective of general station conditions at all times. In
17 an emergency situation, however, should the Shift Supervisor choose to perform manipulative functions to ensure that the plant is in a safe condition, he shall coordinate his actions with the Chief Shift Operator. Whenever he determines that the safety of the reactor is in immediate jeopardy or when operating parameters exceed any of the reactor protection circuit set points and automatic shutdown should but does not occur, he has the responsibility and the authority to order shutdown of the reactor, or to personally effect the shutdown.

17 The Shift Supervisor shall hold an NRC senior reactor operator license. He shall be continuously present at the plant for the duration of his assigned shift until properly

The staff realizes that the necessary knowledge and experience can be gained in a variety of ways. Consequently, credit for equivalent experience should be given to applicants for SRO licenses.

Applicants for SRO licenses at a facility may obtain their 1 yr operating experience in a licensed capacity (Operator or Senior Operator) at another nuclear power plant. In addition, actual operating experience in a position that is equivalent to a Licensed Operator or Senior Operator at military propulsion reactors will be acceptable on a one-for-one basis. Individual applicants must document this experience in their individual applications in sufficient detail so that the staff can make a finding regarding equivalency.

Applicants for SRO licenses who possess a degree in engineering or applicable sciences are deemed to meet the above requirement, provided they meet the requirements set forth in Sections A.1.a and A.2 in enclosure 1 in the letter from H. R. Denton and all power reactor applicants and licensees, dated March 28, 1980, and have participated in a training program equivalent to that of a cold Senior Operator Applicant.

The NRC has not imposed the 1-yr experience requirement on cold applicants for SRO licenses. Cold applicants are to work on a facility not yet in operation; their training programs are designed to supply the equivalent of the experience not available to them.

<u>Nine Mile Point Unit 2 Position</u>

The Upgrading of Operator Training and Senior Operator Training for Unit 2 is being performed as described in Section 13.2 of the FSAR. This is also in accordance with the Site Administrative Procedures.

I.A.2.3 ADMINISTRATION OF TRAINING PROGRAMS

FSAR Cross Reference

Section 13.2.1

NUREG-0737 Position

Pending accreditation of training institutions, licensees and applicants for operating licenses will assure that training center and facility instructors who teach systems, integrated responses, transient, and simulator courses demonstrate SRO qualifications and are enrolled in appropriate requalification programs.

The above position is a short-term position. In the future, accreditation of training institutions will include review of the procedure for certification of instructors. The certification of instructors may or may not include successful completion of a Senior Operator examination.

The purpose of the examination is to provide the NRC with reasonable assurance during the interim period that instructors are technically competent. The requirement is directed to permanent members of the training staff who teach the subjects enumerated above, including members of other organizations who routinely conduct training at the facility. There is no intention to require guest lecturers who are experts in particular subjects (reactor theory, instrumentation, thermodynamics, health physics, chemistry, etc) to successfully complete a Senior Operator examination. Nor do we intend to require a system expert, such as the Instrument and Control Supervisor teaching the rod control drive system to sit for a Senior Operator examination. The use of guest lecturers should be limited.

Nine Mile Point Unit 2 Position

The qualification of the training instructors meets the requirements of this task, as described in Section 13.2 of the FSAR.

I.A.3.1 REVISE SCOPE AND CRITERIA FOR LICENSING EXAMINATIONS - SIMULATOR EXAMS

FSAR Cross Reference

Section 13.2.1

NUREG-0737 Position

Simulator examinations will be included as part of the licensing examinations. The administration of simulator examinations will be deferred for applicants whose facilities do not have simulators onsite as of October 1, 1980. These deferred simulator examinations will be initiated by October 1, 1981.

The clarification provides additional preparation time for utility companies and the NRC to meet examination requirements as stated. A study is under way to consider how similar a nonidentical simulator should be for a valid examination. In addition, present simulators are fully booked months in advance.

Application of this requirement was stated on June 1, 1980 to applicants where a simulator is located at the facility. Starting October 1, 1981, simulator examinations will be conducted for applicants of facilities that do not have simulators at the site.

NRC simulator examinations normally require 2 to 3 hr. Normally, two applicants are examined during this time period by two examiners.

Utility companies should make the necessary arrangements with an appropriate simulator training center to provide time for these examinations. Preferably these examinations should be scheduled consecutively with the balance of the examination. However, they may be scheduled no sooner than 2 weeks prior to and not later than 2 weeks after the balance of the examination.

Nine Mile Point Unit 2 Position

All new licensing examinations will utilize a control room simulator. The simulator for Unit 2 has been ordered, and it is expected to be operational in January 1985.

I.B.1.2 INDEPENDENT SAFETY ENGINEERING GROUP

FSAR Cross Reference

23 Sections 13.4, 16.6.2

NUREG-0737 Position

Each applicant for an operating license shall establish an onsite independent safety engineering group (ISEG) to perform independent reviews of plant operations.

The principal function of the ISEG is to examine plant operating characteristics, NRC issuances, Licensing Information Service advisories, and other appropriate sources of plant design and operating experience information that may indicate areas for improving plant safety. The ISEG is to perform independent review and audits of plant activities, including maintenance, modifications, operational problems, and operational analysis and to aid in the establishment of programmatic requirements for plant activities. Where useful improvements can be achieved, it is expected that this group will develop and present detailed recommendations to corporate management for such things as revised procedures or equipment modifications.

Another function of the ISEG is to maintain surveillance of plant operations and maintenance activities to provide independent verification that these activities are performed correctly and that human errors are reduced as far as practicable. ISEG will then be in a position to advise utility management on the overall quality and safety of operations. ISEG need not perform detailed audits of plant operations and shall not be responsible for signoff functions such that it becomes involved in the operating organization.

The new ISEG shall not replace the plant operations review committee (PORC) and the utility's independent review and audit group as specified by current staff guidelines (Standard Review Plan, Regulatory Guide 1.33, Standard Technical Specifications). Rather, it is an additional independent group of a minimum of five dedicated, full-time engineers, located onsite but reporting offsite to a corporate official who holds a high level, technically-oriented position that is not in the management chain for power production. The ISEG will increase the available technical expertise located onsite and will provide continuing, systematic, and independent assessment of plant activities. Integrating the Shift Technical

Advisors (STAs) into the ISEG in some way would be desirable in that it could enhance the group's contact with the knowledge of day-to-day plant operations to provide additional expertise. However, the STA on shift is necessarily a member of the operating staff and cannot be independent of it.

It is expected that the ISEG may interface with the quality assurance (QA) organization, but preferably should not be an integral part of the QA organization.

The functions of the ISEG require daily contact with the operating personnel and continued access to plant facilities and records. The ISEG review functions can therefore best be carried out by a group physically located onsite. However, for utilities with multiple sites, it may be possible to perform portions of the independent safety assessment function in a centralized location for all the utility's plants. In such cases, an onsite group still is required, but it may be slightly smaller than would be the case if it were performing the entire independent safety assessment function. Such cases will be reviewed on a case-by-case basis.

At this time, the requirement for establishing an ISEG is being applied only to applicants for operating licenses in accordance with Task I.B.1.2. The staff intends to review this activity in about a year to determine its effectiveness and to see whether changes are required. Applicability to operating plants will be considered in implementing long-term improvements in organization and management for operating plants (Task I.B.1.1).

Nine Mile Point Unit 2 Position

An onsite independent safety engineering group (ISEG) will be established to perform independent reviews of plant operation. The principal function of the ISEG is to examine plant operating characteristics and the various NRC and industry licensing and service advisories, and to recommend areas for improving plant operations or safety. The ISEG will perform independent review of plant activities, including maintenance, modifications, operational concerns and analysis and make recommendations to the Supervisor Technical Support Nuclear. | 17

The Supervisor Technical Support Nuclear (or his designee) will present to the Operations Assessment Committee (OAC) and/or the Technical Superintendent the results of the analysis, including (when useful improvements can be achieved) detailed recommendations such as revised procedures or equipment modifications. Presentations to the SORC are provided by the OAC (Section 13.4).

The ISEG will observe plant operations and maintenance activities to determine that these activities are being performed properly and provide written recommendations (when useful improvements can be achieved). The ISEG does not perform detailed (QA-type) audits and is not responsible for signoff functions associated with daily operational activities. The ISEG is independent of the SORC and SRAB, but may make recommendations to these groups.

The ISEG shall be composed of at least five dedicated,
full-time engineers located onsite, assigned to Unit 2, who
report to the Supervisor Technical Support Nuclear. Each
shall have a bachelor's degree in engineering or related
26 science and at least 2 years professional level experience
in his field, at lease 1 year of which experience shall be
in the nuclear field. The Supervisor Technical Support
Nuclear reports to the Superintendent Technical Services
Nuclear who reports to the Technical Superintendent who is
responsible for all technical support onsite.

Although the Technical Department reports to the General Superintendent Nuclear Generation (who is responsible for operations), the Technical Department is independent from the direct operational supervision of the plant (that responsibility resides with the Station Superintendent). Additionally, the Technical Department has recourse to resolve safety concerns by addressing such concerns to either the SRAB or the Vice President Nuclear Engineering and Licensing.

Nine Mile Point Unit 2 Position

Unit 2 will utilize administrative and training procedures to implement operating experience feedback to the plant staff. These procedures will:

1. Clearly identify organizational responsibilities for review of operating experience, the feedback of pertinent information to operators and other personnel, and the incorporation of such information in training and requalification training programs (Section 13.2.4.1.1, Item 9).

2. Identify the administrative and technical review steps necessary to translate recommendations by the Operating Assessment Committee (OAC) into plant actions (e.g., changes to procedures and operating orders). Sections 13.4 and 1.10 provide information concerning the OAC.

3. Identify the recipients of various categories of operating experience information (i.e., shift or supervisor, personnel) or otherwise provide means through which such information can be readily related to the job functions of the recipients (Section 13.2.4.1.3). 17

4. Provide means to ensure that affected personnel become aware of and understand information of sufficient importance so that this information should not wait for emphasis through routine training and retraining, standing orders or night orders. (For example, required reading assignments are made on an ongoing basis to address this concern.)

5. Ensure that plant personnel do not routinely receive extraneous information on operating experience in such volume that it could obscure priority information.

6. Provide suitable checks to ensure that correct information is conveyed to operators and other personnel.

7. Provide periodic audits to ensure that the feedback program functions effectively (e.g., training audits).

Operating experience assessment is performed on an ongoing basis by the Technical Support Group, OAC, and SORC as described in the administrative procedures. The individuals involved review information from a variety of sources such
17 as IE Bulletins, IE Information Notices, INPO reports, LERs, and vendor information letters, such as SILs.

The feedback system provides for early notification of significant information to operating personnel and management. The evaluation process, specifically the OAC meeting, provides assurance that the information is correct and that unimportant and extraneous information does not impact overall proficiency.

3. Improvements in the safety monitoring and human factors enhancement of controls and control displays.

4. Communications from the control room to points outside the control room, such as the onsite technical support center, remote shutdown panel, offsite telephone lines, and to other areas within the plant for normal and emergency operation.

5. Use of direct rather than derived signals for the presentation of process and safety information to the operator.

6. Operability of the plant from the control room with multiple failures of nonsafety-grade and nonseismic systems.

7. Adequacy of operating procedures and operator training with respect to limitations of instrumentation displays in the control room.

8. Categorization of alarms, with unique definition of safety alarms.

9. Physical location of the shift supervisor's office either adjacent to or within the control room complex.

Prior to the onsite review/audit, the Office of Nuclear Reactor Regulation will require a copy of the applicant's preliminary assessment and additional information which will be used in formulating the details of the onsite review/audit.

Nine Mile Point Unit 2 Position

The Unit 2 project will utilize the guidance provided by the NRC Committee to Review Generic Requirements (CRGR) as stated in SECY 82-111.

NMPC has performed a preliminary control room design review based on the BWR Owners Group program. The survey was structured with a team consisting of representatives from NMPC, other utilities, the NSSS supplier, and a human factors consultant. This group included licensed Senior Reactor Operators.

The review included panel layout and design, instrumentation, hardware, and annunciators. The preliminary review was set up to identify areas where potential changes could be made in the PGCC shop prior to shipment to the site in early 1983. The final control room design review will be conducted during 1983 or 1984 based on the guidance of NUREG-0700. The following paragraphs provide a description of this review.

Purpose and Scope The purpose of the control room design review described is to 1) review and evaluate the control room workspace, instrumentation, controls, and other equipment from a human factors engineering point of view that takes into account both system demands and operator capabilities; and 2) to identify, assess, and implement control room design modifications that improve control room man-machine interfaces. The scope of the Unit 2 control room design review described covers the human factors engineering aspects of the completed control room.

Objectives The control room design review will accomplish the following objectives:

1. To determine whether the control room provides the system status information, control capabilities, feedback, and analytic aids necessary for control room operators to accomplish their functions effectively.

2. To identify characteristics of existing control room instrumentation, controls, other equipment, and physical arrangements that may detract from operator performance.

3. To analyze and evaluate the problems that could arise from discrepancies of Items 1 and 2, and to analyze means of correcting those discrepancies.

4. To define and put into effect a plan of action that applies human factors principles to improve control room design and enhance operator effectiveness. Particular emphasis will be placed on improvements affecting control room design and operator performance under abnormal or emergency conditions.

5. To integrate the control room design review with other areas of human factors inquiry identified as a result of TMI-related requirements.

room is separated into a primary display and a secondary display. The secondary display is also utilized for main generator temperature monitoring.

At this time the nuclear data link (NDL) has not been defined by the NRC and no equipment has been procured for this purpose.

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Criterion 2

The licensee shall establish an onsite radiological and chemical analysis capability to provide, within 3-hr time frame established above, quantification of the following:

1. Certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g., noble gases; iodines and cesiums, and nonvolatile isotopes);

2. Hydrogen levels in the containment atmosphere;

3. Dissolved gases (e.g., H^2), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids.

4. Alternatively, have inline monitoring capabilities to perform all or part of the above analyses.

Clarification 2

1. A discussion of the counting equipment capabilities is needed, including provisions to handle samples and reduce background radiation to minimize personnel radiation exposures (ALARA). Also a procedure is required for relating radionuclide concentrations to core damage. The procedure should include: 7

   a. Monitoring for short- and long-lived volatile and non-volatile radionuclides (see Vol. II, Part 2, pp. 524-527 of Rogovin report for further information).

   b. Provisions to estimate the extent of core damage based on radionuclide concentrations and taking into consideration other physical parameters such as core temperature data and sample location.

2. Show a capability to obtain a grab sample, transport and analyze for hydrogen.

3. Discuss the capabilities to sample and analyze for the accident sample species listed here and in Regulatory Guide 1.97, Rev. 2.

4. Provide a discussion of the reliability and maintenance information to demonstrate that the

selected on-line instrument is appropriate for this application. (See (8) and (10) below relative to back-up grab sample capability and instrument range and accuracy).

Position 2

Response: (2)

The reactor coolant and containment atmosphere samples from the PASS can be analyzed for major fission product concentrations by gamma ray spectral analysis. The samples may be diluted by a factor of up to 10^6 to obtain activities permitting isotopic analysis on a germanium crystal detector. The samples are handled using long tongs and lead brick shielding to reduce radiation exposure to a level as low as reasonably achievable. The concentrations of Kr-85, I-131, Cs-137, and Xe-133 are corrected for dilution, decay, temperature, and pressure to the time of reactor shutdown. The extent of fuel damage can then be determined directly
20 from the figures provided in the plant emergency procedures.

Hydrogen levels in the containment can be measured by the Containment Atmosphere Monitoring System. The hydrogen analyzer is environmentally qualified in accordance with Regulatory Guide 1.89 to operate satisfactorily following a LOCA. The hydrogen concentration is recorded in the main control room.

Alternatively, a grab sample of the containment atmosphere can be obtained by the PASS and analyzed for hydrogen concentration by using a gas chromatograph.

Boron content of reactor coolant can be determined by analyzing the diluted reactor coolant sample by the carminic acid method. The sample is handled in the laboratory with long tongs and lead brick shielding to reduce radiation exposure.

Total dissolved gas levels in the reactor coolant can be determined by measuring the pressure of the gas collected from a degassed sample of coolant.

A sample of the dissolved gases can be obtained and analyzed for hydrogen or oxygen content using a gas chromatograph.

TABLE II.B.3-1

TIME AND DOSE PROJECTIONS FOR PASS SAMPLING, TRANSPORT, AND ANALYSIS

Task	Time (min) Start	Time (min) Stop	Exposure(2) (mR) Persons(1)	Exposure(2) (mR) Whole Body	Exposure(2) (mR) Extremities	Notes
Decision to take sample	0	0	NA	N/A	N/A	Assumes TSC and OSC activated and sample room habitated
Read containment atmosphere H_2 levels in control room	0	5	1	NEG	N/A	
Operate control panel for dilute reactor coolant	0	20	4	9.5	9.5	6" lead shielding
Transport dilute reactor coolant to laboratory	20	42	2	3.6+1	2.5+2	6" lead shielding (Max) 3" lead shielding (Min)
Prepare coolant for isotopic	42	44.5	1	5.0-1	6.3+1	4" lead glass for W.B. (Max) 1/2" lead shielding (Min)
Perform isotopic analysis of coolant	44.5	49.5	1	2.2-A	2.0-1	
Analyze coolant for Boron	49.5	54.2	1	2.5	8.6+1	4" lead glass + 2" lead for W.B. 1/2" lead shielding
Prepare sample panel for containment atmosphere	20	20	2	0	0	6" lead shielding 28
Operate control panel for containment atmosphere	20	35	2	4.8+0	4.8+0	2" lead shielding
Transfer containment atmosphere to small cask	35	39.8	1	1.8+1	2.4+2	2" lead shielding
Transport containment atmosphere to laboratory	39.8	58.5	2	5.8+2	2.4+3	3" lead shielding
Prepare containment atmosphere for isotopic	58.5	63.9	1	3.3	5.2+2	4" lead glass & 2" lead for W.B. (Max) 1/2" lead shielding (Min)
Perform isotopic analysis of containment atmosphere	63.9	68.9	1	2.7-3	2.0+0	
Operate control panel for total dissolved gas	39.8	109.8	3	2.5+1	2.5+1	6" lead shielding

TABLE II.B.3-1 (Cont)

Task	Time (min) Start	Time (min) Stop	Exposure(2) (mR) Persons(1)	Exposure(2) (mR) Whole Body	Exposure(2) (mR) Extremities	Notes
Operate control panel for 10-ml reactor coolant	109.8	119.8	3	3.6+0	3.6+0	6" lead shielding
Transport 10-ml reactor coolant to laboratory	119.8	179.1	3	6.0+1	3.8-3	6" lead shielding (Max) 2" lead shielding (Min)
Analyze 10-ml reactor coolant for chloride	179.1	183.6	1	2.4+1	8.1+3	4" glass lead & 2" lead for W.B. (Max) 1/2" lead shielding (Min)

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(1)Number of persons performing particular task.
(2)Doses are based on the assumption that the decision to take a sample is made 1 hr after reactor scram.

TABLE II.B.3-2

POST-ACCIDENT SAMPLING ANALYTICAL METHODS

Analysis	Method	Suitability	Range	Accuracy	
Boron	Carminic acid	GE NEDC-30088 In-house testing	50-2,000 ppm	±50 ppm	14
Chloride	Specific ion electrode	ASTM D512D In-house testing	1-10 ppm >10 ppm	±1 ppm ±10%	14
pH	Combination pH electrode	GE NEDC-30088	2-12 pH	±0.2 pH	
Isotopic	Gamma spectral analysis	In-house testing	1uCi/gm-10 Ci/gm	±200%	14
Total Dissolved Gas[1]	Gas sample pressure measurements	GE testing In-house testing	25-50 cc/kg 50-400 cc/kg	±50% ±30%	14
Dissolved H_2 or O_2	Gas chromatograph and pressure measurements	GE testing	25-50 cc/kg 50-400 cc/kg	±50% ±30%	14
Hydrogen[2]	Gas chromatograph	In-house testing	0.1-100 %	±0.1%	
Oxygen[2]	Gas chromatograph	In-house testing	0.5-100 %	±0.5%	

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(1) Verification is inconclusive.
(2) Backup analysis for on-line H_2/O_2 monitoring system

II.D.1 RELIEF AND SAFETY VALVE TEST REQUIREMENTS

<u>FSAR Cross Reference</u>

Sections 5.2, 5.4

<u>NUREG-0737 Position</u>

BWR licensees and applicants shall conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

<u>Nine Mile Point Unit 2 Position</u>

The NRC has identified a total of 20 scenarios that could possibly lead to high pressure two-phase or liquid flow through the SRV.

The Unit 2 project will provide the following means to resolve the NRC concerns:

1. Redundant Level 8 trip for RCIC (Events 4 and 9)

2. Redundant Level 8 trip for HPCS (Events 5 and 10)

3. Redundant nonsafety Level 8 trip to close the three feedwater control valves and two HPLF valves (Event 1)

The tests and analyses described in Reference 1 verify the adequacy of safety relief valves (SRV) operation and the integrity of the SRV piping under expected liquid discharge conditions, and satisfy all requirements of NUREG-0737, Item II.D.1.

As discussed in Appendix A of Reference 1, for Dikkers
valves, there are no material, dimensional or operational
differences between the in-plant valves and the tested
valves. Since the valves are identical, the test results 7
for Dikkers valves are applicable to the corresponding
in-plant valves.

<u>Reference</u>

1. Analysis of Generic BWR Safety/Relief Valve Operability Test Results, NEDO-24988, Class I, October 1981.

In a letter from D.G. Eisenhut of the NRC to C.V. Mangan of NMPC dated March 29, 1984, the Equipment Qualification Branch requested that NMPC provide additional information concerning TMI Action Plan II.D.1. Following are the responses to each NRC question:

23 Question 1(A)

The test program utilized a rams head discharge pipe configuration. Most plants utilize a tee quencher configuration at the end of the discharge line. Describe the discharge pipe configuration used at your plant and compare the anticipated loads on valve internals in the plant configuration to the measured loads in the test program. Discuss the impact of any differences in loads on valve operability.

Response

Unit 2 utilizes a tee quencher at the end of the main steam SRV discharge line (SRVDL). The test program described in NEDE-24988-P used a rams head discharge device with test conditions simulating the shutdown cooling mode. The impact of the difference on valve operability is accounted for as follows:

- Valve operability is affected by dynamic loads on valve internals. The dynamic loads are governed by (a) back pressure of the SRV and (b) flow through the SRV. Higher back pressures and flow will produce higher dynamic loads.

  (a) In the test program, the SRV inlet pressure was equal to 250 psig. The Unit 2 reactor pressure during shutdown cooling mode is approximately 135 psig. The maximum back pressure of the SRV is approximately 35 percent of the SRV inlet pressure; thus, the test program has qualified the SRV to work with back pressure of about two times that of Unit 2. This provides adequate margin to offset the difference in using a tee quencher.

  (b) The test program has qualified the SRV with a rams head discharge device. The tee quencher allowed less flow (257 lbm/sec) than the rams head (260 lbm/sec) because it has higher flow resistance. Thus, operability of the SRV for Unit 2 SRVDL with a tee quencher will also be qualified.

Refer to the responses to Questions F421.21 and F421.23 for further information regarding the Unit 2 position. 14

Refer to the response for Task II.F.1 for a discussion of incore thermocouples and to the response for Task I.D.1 for

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An investigation of the feasibility and contraindications of reducing challenges to the relief valves by use of the aforementioned methods should be conducted. Other methods should also be included in the feasibility study. Those changes which are shown to reduce relief valve challenges without compromising the performance of the relief valves or other systems should be implemented. Challenges to the relief valves should be reduced substantially (by an order of magnitude).

Failure of the power-operated relief valve (PORV) to reclose during the TMI-2 accident resulted in damage to the reactor core. As a consequence, relief valves in all plants, including BWRs, are being examined with a view toward their possible role in a small-break LOCA.

The SRVs are dual-function pilot-operated relief valves that use a spring-actuated pilot for the safety function and external air diaphragm-actuated pilot for the relief function.

The operating history of the SRV has been poor. A new design is used in some plants but the operational history is too brief to evaluate the effectiveness of the new design. Another way of improving the performance of the valves is to reduce the number of challenges to the valves. This may be done by the methods described above or by other means. The feasibility and contraindications of reducing the number of challenges to the valves by the various methods should be studied. These changes, which are shown to decrease the number of challenges without compromising the performance of the valves or other systems, should be implemented.

The failure of an SRV to reclose will be the most probable cause of a small-break LOCA. Based on the above guidance and clarification, results of a detailed evaluation should be submitted to the staff. The licensee shall document the proposed system changes for staff approval before implementation.

Nine Mile Point Unit 2 Position

The BWR Owners Group (BWROG) evaluated the NRC-suggested modifications listed earlier. Section 4.3 of the BWROG study (March 31, 1981) states: "For comparing the various valves, the Three-Stage Target Rock Valve was taken as the benchmark valve with an assumed normalized factor of 1.0 for probability to stick open when challenged." Section 4.3.3 compares Crosby and Dikkers SRVs to the three-stage target rock, and states: "Based on valve qualification test data and limited operating experience, a normalized factor of

0.125 was assigned for their relative probability to stick open, when challenged." Since the Unit 2 design includes Dikkers SRVs, a reduction of challenges, relative to the benchmark valve, of roughly one order of magnitude, is achieved; therefore, the intent of the NUREG is satisifed.

The Unit 2 design does not incorporate any of the proposed changes listed in NUREG-0737, since the BWROG study has determined that either unjustified increases in system complexity and/or minimal reduction (less than 5 percent) in SRV challenge rate would result from these changes.

II.K.3.17 REPORT ON OUTAGES OF EMERGENCY CORE-COOLING SYSTEMS LICENSEE REPORT AND PROPOSED TECHNICAL SPECIFICATION CHANGES

FSAR Cross Reference

23 | Section 6.3, 16.3/4.5

NUREG-0737 Position

Several components of the emergency core-cooling (ECC) systems are permitted by technical specifications to have substantial outage times (e.g., 72 hours for one diesel-generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation).

The present technical specifications contain limits on allowable outage times for ECC systems and components. However, there are no cumulative outage time limitations on these same systems. It is possible that ECC equipment could meet present technical specification requirements but have a high unavailability because of frequent outages within the allowable technical specifications.

The licensees should submit a report detailing outage dates and length of outages for all ECC systems for the last 5 years of operation, including causes of the outages. This report will provide the staff with a quantification of historical unreliability due to test and maintenance outages, which will be used to determine if a need exists for cumulative outage requirements in the technical specifications.

Based on the above guidance and clarification, a detailed report should be submitted. The report should contain (1) outage dates and duration of outages; (2) cause of the outage; (3) ECC systems or components involved in the outage; and (4) corrective action taken. Test and maintenance outages should be included in the above listings which are to cover the last 5 years of operation. The licensee should propose changes to improve the availability of ECC equipment, if needed. 9

Applicant for an operating license shall establish a plan to meet these requirements.

Nine Mile Point Unit 2 Position

NMPC will report ECCS outages via LERs and Annual Summary Reports as required by technical specifications.

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II.K.3.22 RCIC SUCTION SOURCE

FSAR Cross Reference

Sections 5.4.6, 7.4

NUREG-0737 Position

The reactor core isolation cooling (RCIC) system takes suction from the condensate storage tank with manual switchover to the suppression pool when the condensate storage tank level is low. This switchover should be made automatically. Until the automatic switchover is implemented, licensees should verify that clear and cogent procedures exist for the manual switchover of the RCIC system suction from the condensate storage tank to the suppression pool.

Nine Mile Point Unit 2 Position

The Unit 2 project will implement the NRC position to automatically transfer RCIC suction source. Condensate storage tank low water inventory will initiate automatic transfer of the suction of the RCIC pump to the suppression pool.

II.K.3.24 RCIC AND HPCI SUPPORT POWER

FSAR Cross Reference

Section 9.4

NUREG-0737 Position

Long-term operation of the reactor core isolation cooling (RCIC) and high pressure coolant injection (HPCI) systems may require space cooling to maintain the pump room temperatures within allowable limits. Licensees should verify the acceptability of the consequences of a complete loss of ac power. The RCIC and HPCI systems should be designed to withstand a complete loss of offsite ac power to their support systems, including coolers, for at least 2 hr.

Nine Mile Point Unit 2 Position

The Unit 2 ECCS design employs a cubicle arrangement to ensure physical, electrical, and environmental separation of each portion of the ECCS. The RCIC system is also located within a separate cubicle. The HPCS pump room is cooled by either of two fully redundant Category I unit space coolers. The remaining ECCS pump rooms and the RCIC pump room are each cooled by one Category I unit space cooler with an additional cooler provided as a spare. These coolers are part of the reactor building heating, ventilation, and air conditioning (HVAC) system which utilize cooling water from the service water (SWP) system. The safety-related portions of the SWP system are powered from the standby diesel generators following a loss of offsite power; therefore a reliable supply of cooling water is provided. Likewise, the control systems involved in the operation of the unit coolers also receive their power from the diesel generators following a loss of offsite power. This design assures that the pump room temperatures are maintained within normal limits for an indefinite period following a complete loss of offsite power.

II.K.3.27 COMMON WATER LEVEL REFERENCE

FSAR Cross Reference

Sections 7.3, 16.3/4.3 23

NUREG-0737 Position

Different reference points of the various reactor vessel water level instruments may cause operator confusion. Therefore, all level instruments should be referenced to the same point. Either the bottom of the vessel or the top of the active fuel is a reasonable reference point (NUREG-0737).

Nine Mile Point Unit 2 Position

Unit 2 utilizes a common water level reference elevation at 380.69 in above the vessel invert elevation. This reference 23
point corresponds to the top of the upper core support plate. All five level instrumentation ranges (shutdown, upset, wide, narrow, and fuel) utilize this reference.

II.K.3.28 ADS ACCUMULATORS

FSAR Cross Reference

23 Sections 5.2, 6.3, 9.3.1

NUREG-0737 Position

Safety analysis reports claim that air or nitrogen accumulators for the automatic depressurization system (ADS) valves are provided with sufficient capacity to cycle the valves open five times at design pressure. GE has also stated that the emergency core cooling systems (ECCS) are designed to withstand a hostile environment and still perform their function for 100 days following an accident. The licensee should verify that the accumulators on the ADS valves meet these requirements, even considering normal leakage. If this cannot be demonstrated, the licensee must show that the accumulator design is still acceptable.

The ADS valves, accumulators, and associated equipment and instrumentation must be capable of performing their functions during and following exposure to hostile environments, taking no credit for nonsafety-related equipment or instrumentation. Additionally, air (or nitrogen) leakage through valves must be accounted for in order to assure that enough inventory of compressed air is available to cycle the ADS valves.

Nine Mile Point Unit 2 Position

The primary source of pneumatic supply and leakage makeup for the ADS accumulators will be from two nitrogen storage tanks located outside the reactor building. Long-term post-accident supply and leakage makeup will be provided by two bottled nitrogen connections, also located outside the reactor building. Two Category I nitrogen accumulator tanks are located in the reactor building and are pressurized from the nitrogen storage tanks. These two large accumulators provide pneumatic supply and leakage makeup for the seven smaller ADS accumulators located inside the primary containment. This arrangement provides sufficient time to place the bottled nitrogen system into service if the plant condition requires long-term ADS operation.

The ADS valves, including pilot operators, are designed to withstand a hostile environment and still perform their safety function for 100 days following an accident.

TABLE III.D.3.4-1

RESULTS OF TOXIC CHEMICAL ANALYSIS FOR THE CONTROL ROOM HABITABILITY STUDY

Chemical Location	Chemical	Maximum Control Room Concentration (g/m^3)	Toxic Limit (g/m^3)	Allowable Time Period (min)
J.A. FitzPatrick Plant	N_2	7.5	274	15
	H_2SO_4	6.6×10^{-5}	0.002	2
	CO_2	4.3	54.8	15
	Propane	0.9	43.1	15
Alcan	Cl_2	0.02	0.045	2
	Propane	3.5	43.1	15
	N_2	0.9	274	15
	HCl	0.02	0.05	15
	CO_2	0.06	54.8	2
Route 104	HCl	0.04	0.050	2
	N_2	0.4	274	15
	CO_2	0.06	54.8	2
Nine Mile Point Unit 1	N_2	15.0	274	15
	CO_2	10.2	54.8	15
	H_2SO_4	1.3×10^{-4}	0.002	2
Nine Mile Point Unit 2	H_2SO_4	0.0017	0.002	2
	CO_2	32.8	54.8	15
	Halon 1301	4.0	432	15
	N_2	20.5	274	15
Copper Weld Bimetallics Group	Isopropyl Alcohol	4.0×10^{-4}	1.2	15

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In addition to the load combination requirement for the containment design, there is a fatigue analysis requirement for the liner of a concrete containment. For steel containment, the consideration of fatigue is specified in ASME Boiler and Pressure Vessel Code Section III, Division 1, Subsection NE. However, the liner on the concrete foundation mat of the steel containment should be treated as the liner of a concrete containment. Since the staff's position requires the pool liner to be designed in accordance with the ASME B&PV Code Section III, Division 1, Subsection NE, it is suggested that a generic method to consider fatigue of both the steel containment and the steel liner in the concrete containment should be adopted.

Position

The absolute sum method of combining dynamic loads is used for the design of structures. The details of load combinations used in designing the structures are covered in FSAR Section 3.8. 3

The Unit 2 primary containment liner is evaluated for fatigue to the requirements of ASME Boiler and Pressure Vessel Code Section III, Division 1, Subsection NE.

LICENSING ISSUE: 43 - FLUID/STRUCTURE INTERACTION

Issue

The dynamic forcing functions for various loads have been established through testing on models that are generally more stiff than the actual structures to which the loads will be applied. By directly applying such forcing functions to actual structures in the analysis, the interactive effect between the fluid mass and the structure is neglected. Under certain conditions, this effect may be significant. It is proposed that a generic approach to study such effects should be established.

Position

This issue is not directly applicable to the Unit 2 Mark II containment. Since the Unit 2 containment is stiff in the suppression pool region and the dynamic forcing functions are conservatively defined, any interactive effect between the fluid mass and the structure is inherently included.

LICENSING ISSUE 44 - LONG-TERM POST-LOCA OPERABILITY OF DEEP-DRAFT ECCS PUMPS

Issue

IE Bulletin 79-15, dated July 1979, identified problems with deep-draft ECCS pumps that could threaten their long-term post-LOCA operability. Structure flexibility; shaft/column misalignment; vibrational frequencies near rotation speeds; inlet flow induced vortices; and dimensional deficiencies such as those discovered with certain LaSalle ECCS pumps, could cause excessive vibration and bearing wear. The NRC staff has asked applicants to define programs and provide data that compare the expected service life with the accumulated operating time and confirm the long-term operability.

Position

4 The inherent design features of the Byron Jackson ECCS pumps in Unit 2 preclude excessive vibration and bearing wear. Each pump is supplied with a casing or suction barrel and is not installed in a wet sump. They do not have long, limber columns; the longest pump is only 24 ft, compared to the 30- to 60-ft pumps described in IE Bulletin 79-15. Also the pump assembly rigidity is enhanced by seismic rings between the assembly and the barrel. The pumps use a double-suction first stage to provide stability over a wide range of flows. Column frequencies are well removed from pump speed. Larger diameter barrels provide low flow velocities around pump inlets, and ring seismic restraints act as flow straighteners to suppress vortex formation. The pumps have high-precision, keyed, sleeve-type couplings.

Long-term operability is assured by preventive maintenance, functional testing and surveillance, and vibration monitoring. Scheduled preventive maintenance consists of resistance readings of motor windings; lubrication of critical rotating components; general cleaning and inspection of rotating electrical equipment; and inspection, overhaul, alignment, and adjustment of impeller lift. Functional-testing measurements of pump inlet pressure, differential pressure, flow rate, vibration, and upper temperature, as prescribed by Section XI of the ASME B&PV Code, provide data for engineering analysis to identify performance changes or trends. In addition, vibration data bases, established during the preoperational/startup testing, are compared with functional-testing vibration data to monitor journal bearing wear and shaft whip.

ISSUE: A-24 - ENVIRONMENTAL QUALIFICATION OF SAFETY-RELATED ELECTRICAL EQUIPMENT

NRC Description 9

Accidents postulated for nuclear power plants could create severe environmental conditions such as temperature, pressure, humidity, radiation, chemical sprays, and submergence both inside and outside the containment. In order to ensure that the electrical equipment in safety systems will perform their intended function, it is required that such equipment be qualified to perform in the environment associated with an accident.

Schedule for NRC Resolution

NUREG-0588, Revision 1, completed August 1981.

IEEE-323 and Regulatory Guide 1.89 contain specific guidance for meeting the requirements. The final rule concerning environmental qualification was published in the Federal Register on January 21, 1983.

Unit 2 Position

Environmental qualification of Class 1E equipment located in harsh environments meets or exceeds the requirements for Category II qualification in accordance with NUREG-0588, including the guidance provided for incorporation of IEEE-323. The mild environments qualification program has not been addressed to the NRC.

ISSUE: A-26 - REACTOR VESSEL PRESSURE TRANSIENT PROTECTION

9 NRC Description

Pressure transients in PWRs which have exceeded the pressure/temperature limits of the reactor vessel have occurred (usually during plant startup or shutdown, when the temperature of the reactor coolant was low). The transients have been attributed to personnel error, procedural deficiencies, component random failure, and spurious valve actuation.

Schedule for NRC Resolution

NUREG-0224 completed September 1978. All operating PWRs have an installed system to protect against low temperature overpressurization. However, systems in 10 plants have not been completely reviewed against acceptance criteria.

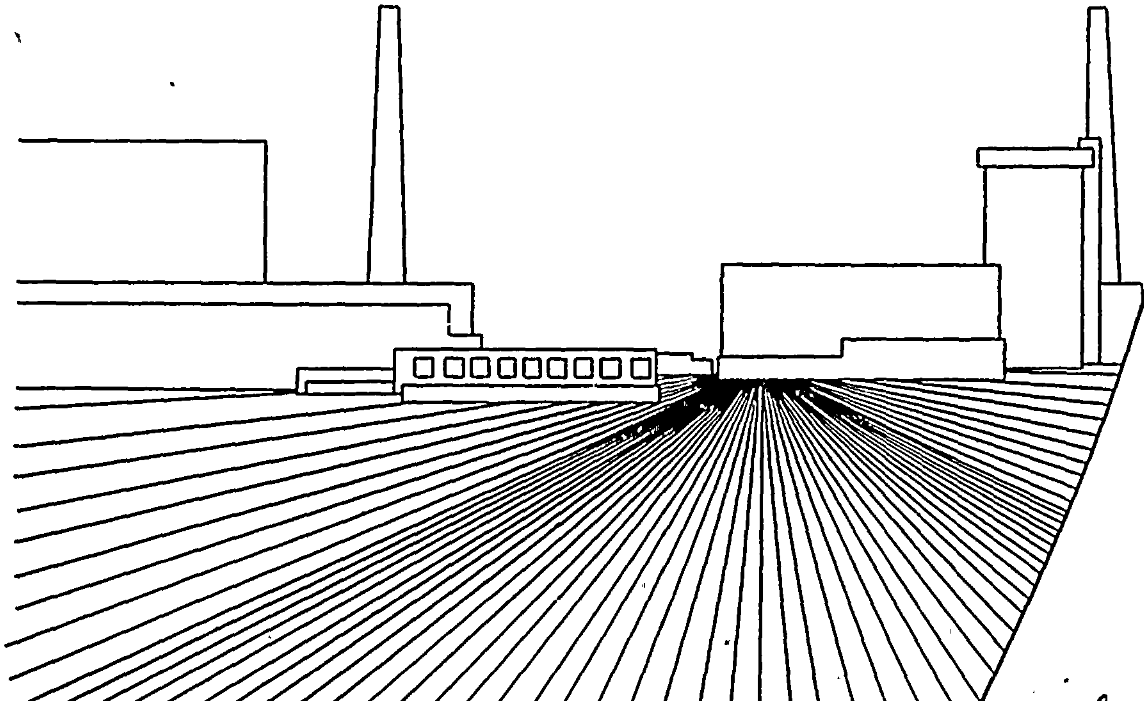
Unit 2 Position

As Unit 2 is a BWR, this issue is not applicable.

FINAL SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION — UNIT 2

NIAGARA MOHAWK



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CHAPTER 2

SITE CHARACTERISTICS

2.1 GEOGRAPHY AND DEMOGRAPHY

2.1.1 Site Location and Description

Unit 2 is located on the western portion of the Nine Mile Point promontory approximately 274 m (900 ft) due east of Nine Mile Point Nuclear Station Unit 1. The eastern portion of the promontory is owned by the Power Authority of the State of New York (NYPA) which owns the James A. FitzPatrick Nuclear Power Plant[1].

2.1.1.1 Specification of Location

The site is adjacent to Lake Ontario in Oswego County, NY, approximately 10 km (6.2 mi) northeast of the city of Oswego. The Unit 2 reactor is located at latitude 43 deg, 31 min, 17 sec north and longitude 76 deg, 24 min, 27 sec west. The Universal Transverse Mercator (UTM) coordinates are N 4,819,478 m and E 386,254 m. Figure 2.1-1 shows the area surrounding the site within an 80-km (50-mi) radius.

Lake Road, a private, hard-surfaced, east-west road, crosses the site and provides a connection with County Route 1A. County Route 1A connects to County Route 1 and extends to the city of Oswego to the west. On the east, Lake Road joins County Route 29 which connects with State Highway 104 6.2 km (3.9 mi) southeast of the site. A spur of the Consolidated Railroad Corporation provides rail service to the station[2]. There are no residential, agricultural, or in- | 26
dustrial developments on the site other than Nine Mile Point Unit 1 and the James A. FitzPatrick plant, which are both operating nuclear power plants. The site area is posted as private property, and access to the station buildings is controlled.

2.1.1.2 Site Area Map

Main plant structures and the cooling tower occupy approximately 9.3 ha (22.9 acres) of the total site area of 364 ha (900 acres).

Figures 2.1-2 and 2.1-3 show the Unit 2 site plan including property and exclusion area boundaries, principal structures for Units 1 and 2, ground contours, railroads, highways, and transmission lines in the site area.

2.1.1.3 Boundaries for Establishing Effluent Release Limits

The minimum distance from Unit 2 to the EAB is approximately
3 1.4 km (0.87 mi) to the southwest. Exclusion area distances
for the site are shown on Figure 2.1-2.

The restricted area for the station follows the same boundary as the exclusion area. Lake Road provides access from Lakeview Road and County Road 29 to Nine Mile Point Units 1 and 2 and to the FitzPatrick plant. Access to the Visitors Center at Nine Mile Point is also from Lake Road. Although Lake Road is privately owned between Lakeview Road and County Road 29, public use is permitted during normal operating conditions. Miner Road provides an alternate route between Lakeview Road and County Road 29. This road
3 is in the town of Scriba. No public use restrictions affect
public use along Miner Road. There are no state or other roads, shipping lanes, or rail lines crossing the restricted area. The Oswego River is located approximately 8.8 km (5.5 mi) west of the restricted area boundary at its closest point.

North of the plant, the restricted area boundary follows the shoreline of Lake Ontario. A fence along the shoreline prevents unauthorized access to Unit 2. Local authorities will notify persons on the lake in the vicinity of the plant of the need to leave the area in the event of an emergency.

The boundary of the restricted area is posted with signs to assure public awareness of access restrictions. During emergency conditions, public access to the restricted area, including the Visitors Center, will not be permitted. The necessary authorities will be contacted to enforce access restrictions from local roads (Section 13.3). The radiation dose outside the restricted area will be within the guidelines of 10CFR20, 10CFR50, Appendix I (Appendix 11B), and 40CFR190.10.

Dose estimates for persons within the restricted area are presented in Section 12.4. There are two gaseous release points for routine airborne radioactive emissions: the combined radwaste/reactor building vent and the stack. Radwaste and reactor vents are combined on the reactor building to form one release point (Figure 11.3-2). Distances from the stack and from the vent to the restricted area boundary are shown in Table 2.1-1 as a function of direction.

2.1.2 Exclusion Area Authority and Control

2.1.2.1 Authority

Distances from the plant to the exclusion area boundary (EAB) are measured from the centerline of the reactor and approximately 1.6 km (1 mi) to the east, 1.4 km (0.87 mi) to the southwest, and over 2.1 km (1.3 mi) to the southern site boundary. Exclusion area distances for the site are shown on Figure 2.1-2.

NMPC is owner in fee of the property within the exclusion
area except for that portion encompassed by the James A.
FitzPatrick site owned by NYPA. The authority which permits 19
NMPC to control activities over that portion of the Unit 2
EAB owned by NYPA is a formal agreement between NMPC and 19
NYPA executed on March 9, 1970, which provides for
reciprocal inclusion of each party's project property in the
exclusion area for Nine Mile Point Units 1 and 2 and The
James A. FitzPatrick Nuclear Power Plant. No one resides in
the exclusion area and no easements have been granted within
the EAB, except such agreements between NMPC and NYPA for 19
joint use of facilities and access to them for that purpose.
The Emergency Plan (Section 13.3) discusses the means of
control of this area in the event of an accident.

A private, hard-surfaced, east-west road crosses the site connecting with Oswego County Highway Route 29. A spur of the Consolidated Railroad Corporation provides rail service to the station. Since the site is located on a navigable portion of Lake Ontario, the station is accessible by barge for construction and supply purposes.

2.1.2.2 Control of Activities Unrelated to Plant Operation

The Energy Information Center is owned by NMPC and NYPA and 19
is located on the site west of Nine Mile Point Unit 1. The
center has averaged more than 50,000 visitors annually since
its official opening in 1967. The center provides visitor
facilities including educational exhibits, picnic and
playground areas, and nature study trails. Control of
recreational activities in the vicinity of the plant is
discussed in the Emergency Plan (Section 13.3).

As discussed in Section 13.3, a study for evacuation of area population surrounding the plant was performed. Calculated doses received by any individual in this area in the event of an accident are within allowable limits (Chapter 15). Plant tours normally are not provided due to security and insurance restrictions.

2.1.2.3 Arrangements for Traffic Control

The exclusion area is traversed by one road and a rail spur (Section 2.1.2.1). Under emergency conditions, the appropriate authority (Section 13.3) is contacted in the event that it becomes necessary to control traffic on Lake Road. When requested, the Consolidated Railroad Corporation controls railroad traffic through the exclusion area.

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2.1.2.4 Abandonment or Relocation of Roads

No public roads within the exclusion area have been abandoned or relocated.

2.1.3 Population Distribution

2.1.3.1 Population Within 16 km (10 mi)

In 1980, Oswego County had an estimated population of 113,901 at an average density of 43 people/sq km (111 people/sq mi)[3]. This population density is considerably lower than the state average of 137 people/sq km (356 people/sq mi). The 1980 population and population density for the eight towns and one city within 16 km (10 mi) of Unit 2 are listed in Table 2.1-2.

The total 1980 population within 16 km (10 mi) of Unit 2 is estimated to be 35,467. This population is projected to increase to approximately 74,082 by the year 2030[4]. The 16-km (10 mi) area contains all or portions of one city and eight towns: the city of Oswego, and the towns of Minetto, Scriba, New Haven, Oswego, Mexico, Palermo, Volney, and
26 | Richland. City and town boundaries are shown on Figure 2.1-4.

Of the eight towns and one city in the 16-km (10 mi) area, the city of Oswego is the largest in population, containing approximately 19,793 people in 1980. Following the city of Oswego in population size are Granby, Scriba, and Volney with estimated 1980 populations of 6,341, 5,455, and 5,358, respectively[3]. Population and the 1970-1980 percent change in population for the towns and city within the 16-km (10 mi) area are listed in Table 2.1-3.

It is expected that a large portion of the population growth in the 16-km (10 mi) area will occur around the southeastern fringes of the city of Oswego, with the surrounding towns absorbing much of the city's satellite growth[5].

Population distribution within 6 km (3.7 mi) of the station is based on the results of a field survey conducted in May 1982. Population distribution between 6 (3.7 mi) and 16 km (10 mi) is based on a house count from U.S. Geological Survey maps, photorevised in 1978, on which

2.1.3.4 Low Population Zone

The low population zone (LPZ) surrounding Unit 2 encompasses an area within a 6.4 km (4 mi) radius from the Nine Mile Point Unit 1 stack. LPZ boundary accident doses for Unit 2 are calculated at a distance of approximately 6.1 km (3.8 mi) from the Unit 2 stack, which is 6.4 km, adjusted for the distance between the Unit 1 and Unit 2 stacks. Figure 2.1-19 depicts the LPZ. The distance for the LPZ was chosen based on the requirements of 10CFR100.11.

The LPZ is expected to contain approximately 2,315 people in the year 1985 at an average density of 48 people/sq km (125 people/sq mi). By the year 2030, the LPZ population is expected to have increased to approximately 4,372 at an average density of 91 people/sq km (236 people/sq mi).

The only facility in the LPZ that attracts a transient population is the Ontario Bible Campground at Lakeview, located approximately 1.5 km (1.0 mi) west-southwest of the station. This campground is a privately-owned facility
operated on a 52-acre lakeshore plot. Groups of up to | 25
500 persons use this camp during the summer and as many as 1,500 people may gather there for short periods on Sundays throughout the summer. The facility is unused during the balance of the year except for an occasional weekend in the spring and fall.

2.1.3.5 Population Centers

In 1980, the closest population center, as defined by 10CFR100, to Unit 2 was the city of Syracuse, which contained approximately 170,105 people. The city's closest corporate boundary to Unit 2 is approximately 53 km (33 mi) south-southeast. The city of Syracuse is part of the Syracuse SMSA, which encompasses Onondaga, Oswego, and Madison Counties.

Based on county-level population projections provided by the New York Department of Commerce, the population of the city of Oswego will exceed 25,000 people and become the nearest population center in the year 2000[4]. This estimate may prove to be somewhat high based on historical growth in the city; however, the estimate is useful because it provides a conservative estimate for use in calculating doses from potential accidents.

Although Oswego City's closest political boundary is approximately 7.24 km (4.5 mi) from the site, no conflict exists with the LPZ/population center distance requirements defined in 10CFR100 since the boundary of the city's residential area is located approximately 8.85 km (5.5 mi) away, over 1.33 times the distance of the LPZ. Future residential growth is not anticipated to decrease this distance since the area between the residential and political boundaries is used and zoned for industry. It is
11 most likely that residential growth will occur to the south and southeast where land is available and more desirable from a residential perspective, rather than into an area of strong industrial character. A zoning map for the city is provided on Figure 2.1-20 which shows the difference between the industrial and residential boundaries closest to the site.

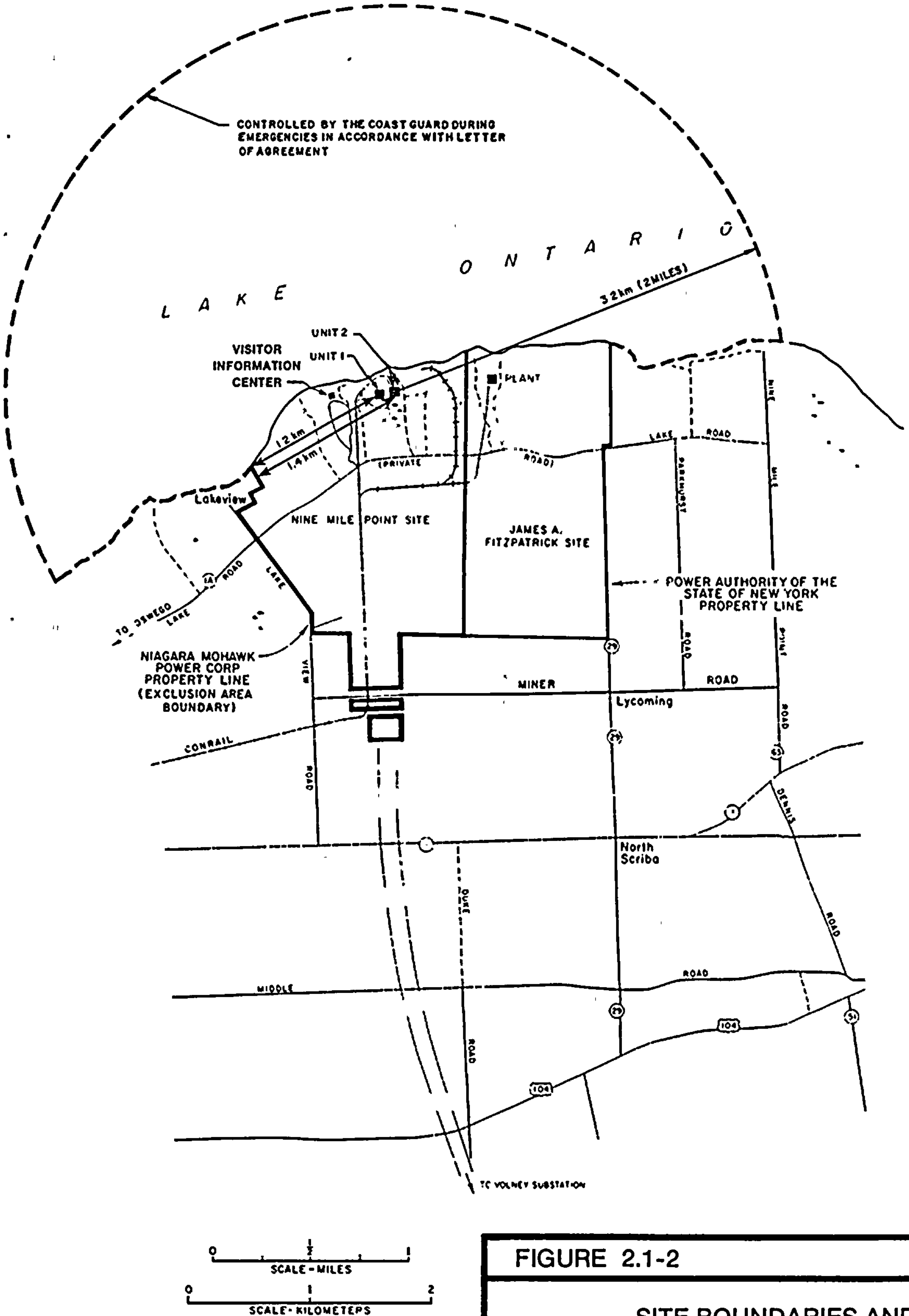


FIGURE 2.1-2

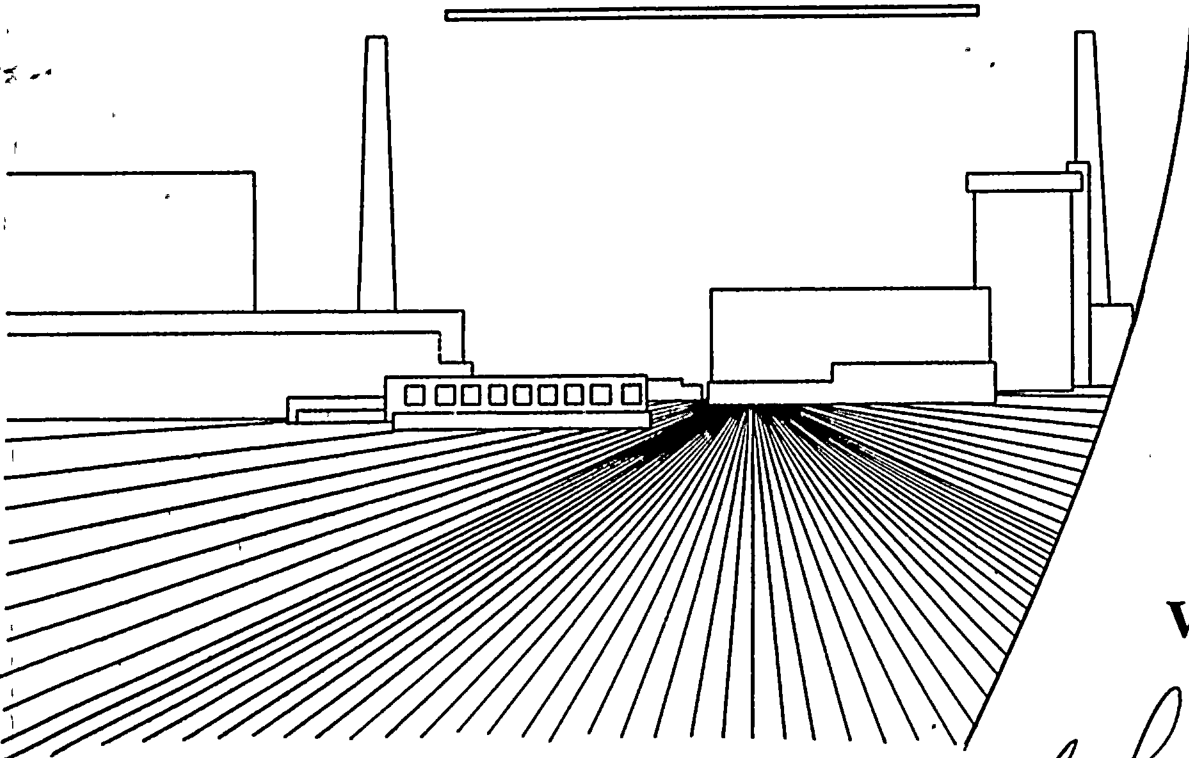
SITE BOUNDARIES AND TRANSPORTATION ROUTES

NIAGARA MOHAWK POWER CORPORATION
NINE MILE POINT-UNIT 2
FINAL SAFETY ANALYSIS REPORT

FINAL SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION — UNIT 2

NIAGARA MOHAWK



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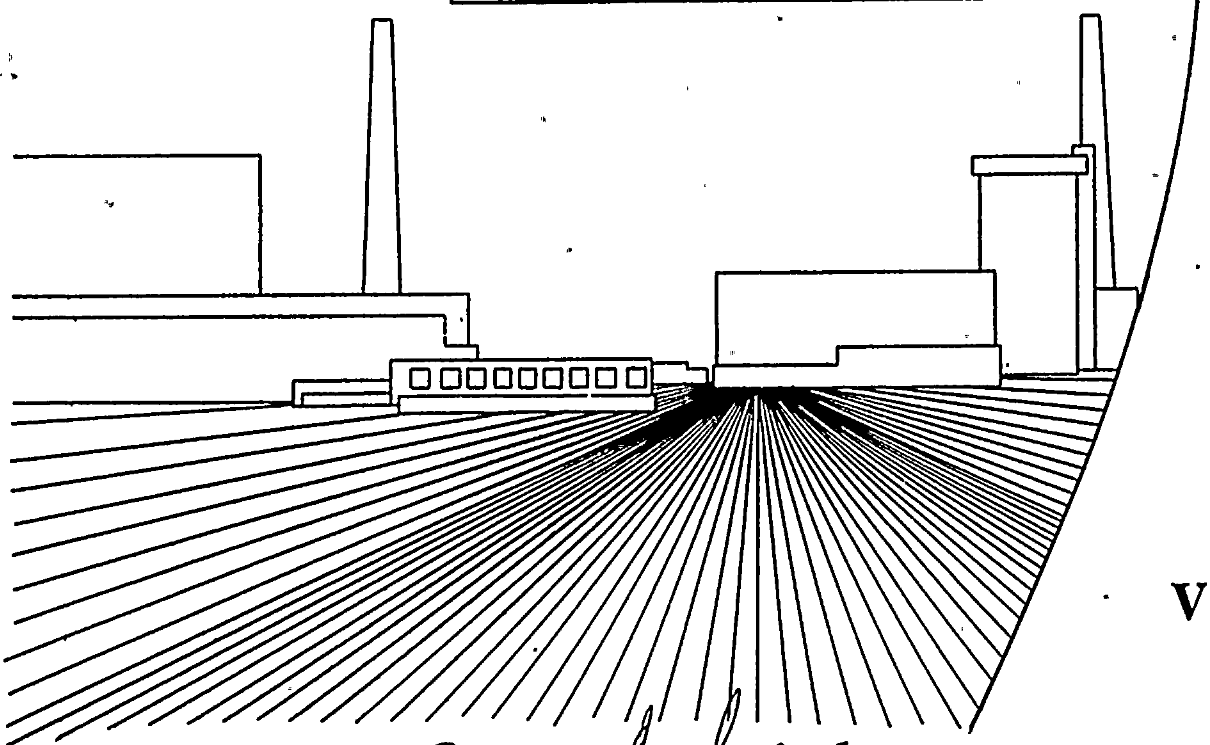
FINAL SAFETY ANALYSIS REPORT

NINE MILE POINT NUCLEAR STATION — UNIT 2

NIAGARA MOHAWK



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9.3 PROCESS AUXILIARIES

9.3.1 Compressed Air Systems

The compressed air systems consist of the instrument air system (IAS), the service air system (SAS), and the breathing air system (AAS). All three compressed air systems are used only for nonsafety-related equipment and components during normal plant operation.

The instrument air system is described in Section 9.3.1.1, followed by descriptions of the service air system and the breathing air system in Sections 9.3.1.2 and 9.3.1.3, respectively.

All instrumentation and control systems located inside the reactor primary containment, including the safety-related equipment and components of the automatic depressurization system (ADS) and the four inboard main steam isolation valve 28
(MSIV) actuator accumulators are independently supplied with nitrogen gas from the instrument nitrogen system (GSN). The automatic depressurization system and the instrument nitrogen systems are described in Sections 9.3.1.4 and 9.3.1.5, respectively.

The four outboard main steam isolation valve (MSIV) actuator 28
accumulators are supplied with air from the reactor building instrument air receiving tank.

9.3.1.1 Instrument Air System

9.3.1.1.1 Design Bases

<u>Safety Design Basis</u>

The instrument air system is not a safety-related control air system. It is not required to effect or support the safe shutdown of the reactor or to perform any safety-related functions associated with its operation.

However, all instrument air system piping, valves, and fittings located in Category I areas are seismically analyzed and supported in accordance with safe shutdown earthquake (SSE) design requirements so that their failure will not damage safety-related equipment, piping, and components.

The instrument air system component design bases are given in Section 3.2.

Power Generation Bases

The instrument air system is designed to supply clean, dry, and oilfree air at 80 to 100 psig to all nonsafety-related plant instrumentation and control systems. However, all instrumentation and control systems located inside the

Each two-stage instrument air compressor assembly includes an intercooler, aftercooler, and air receiver tank. The instrument air compressor cylinders are of the non-lubricated type. The intake air filters and silencers are located on the turbine building roof. Cooling water is supplied to the air compressor cooling water system and heat exchangers from the reactor building closed-loop cooling water system.

Two refrigerant-type air dryers, with two prefilters and two afterfilters, are provided on the instrument air system supply header to filter and dry the air to a dewpoint of 35°F at 125 psig. 27

The instrument air system distribution piping network is supplied from a separate instrument air receiver tank located downstream of the refrigerant dryers and air filters. Instrument air used only for nonsafety-related instrumentation and control systems is distributed throughout the plant from this air receiver tank.

The service air system supply header is branched off the common compressed air supply header upstream of the instrument air dryers and filters. An isolation block valve on the service air system main supply branch header will automatically close and shut off the service air supply when the common compressed air supply header pressure decreases to less than 85 psig. The automatic shutoff and isolation of the service air system is designed to prevent decreased compressed air supply header pressure, as during high service air demand flows, which may adversely affect the operability of the instrument air system.

Each instrument air compressor has automatic unloader controls and a remote manual/automatic selector station for automatic start-stop operation. In the selected lead position the compressor runs continuously after starting and automatically unloads to maintain its air receiver pressure. In the lag position the compressor will automatically start when the common air supply header pressure drops below the low-pressure setpoint of 90 psig. In the backup mode, the compressor will automatically start when the common air supply header pressure decays below the low-low pressure setpoint of 85 psig. The air compressors are operated from the normal plant power supply. Cooling water to the air compressor cooling system heat exchangers is supplied by the reactor building closed loop cooling system (Section 9.2.2.1).

9.3.1.1.3 Safety Evaluation

The three instrument air compressors, i.e., the lead, lag, and backup units, operate to maintain the required pressure at the air receivers which provide the station's instrument air system with an air supply pressure of 100 to 120 psig.

Actuation of the selected lag unit is automatic when the compressed air supply header pressure decreases below 100 psig, and the selected backup unit automatically starts
26 when the header pressure further decays below 85 psig.

The instrument air compressors and air receivers have sufficient capacities to supply the requirements of plant instrumentation and control systems. The loss of instrument and control air causes air-operated valves to fail to appropriate safe positions.

9.3.1.1.4 Inspection and Testing Requirements

The instrument air system operates on a continuous basis. It is maintained and monitored, and abnormal conditions are alarmed during normal plant operation.

The instrument air system will be tested in accordance with the applicable requirements of Regulatory Guide 1.68.

Preoperational testing of the instrument air system is addressed in Table 14.2-43.

9.3.1.1.5 Instrumentation Requirements

<u>Description</u>

Manual and automatic controls are provided for maintaining an adequate supply of instrument air for air-operated instruments, equipment, and components. The controls and monitors described below are located in the main control room. The control system logic is shown on Figure 9.3-2.

<u>Operation</u>

Each instrument air compressor control system has a three-step regulator for free air unloading at constant speed and dual controls for both manual and fully automatic start-stop operation. The three-step regulation allows the compressor to operate at full, one-half, and zero load at rated speed as a function of the system air receiver pressure. The solenoid-operated three-way unloader valve in the control system automatically provides a 15-sec time delay for free increasing the piping internal pressures. Therefore, piping inside the primary containment is protected by thermal relief valves. The piping outside the primary containment is protected by the air compressor and receiver relief valves. Piping in Category I areas has been designed so that its failure will prevent damage to safety-related equipment. With the exception of the containment penetrations and isolation valves, the service air system is nonsafety-related.

9.3.1.2.4 Inspection and Testing Requirements

No special inspection and testing are required following preoperational testing except for ISI of the containment penetrations (Section 6.6).

9.3.1.2.5 Instrumentation Requirements

Description

The air supply for the service air system is provided by the instrument air system. The only controls and monitors for the service air system are an instrument air/service air operated block (globe) valve and its associated alarm which is located in the main control room. The control logic is shown on Figure 9.3-2.

Operation

In the normal mode, the service air system block valve can be opened locally at LCS738 only if a low-low pressure condition does not exist. The valve will close automatically on low-low pressure. The valve can be opened and closed manually. 27

Monitoring

An alarm is provided for service air system block valve closure.

9.3.1.3 Breathing Air System

The breathing air system provides clean, dry, oilfree air to various areas throughout the plant for breathing.

9.3.1.3.1 Design Bases

Safety Design Bases

The breathing air system is not required to effect or support safe shutdown of the reactor ot to perform in the operation of reactor safety features. However, all items contained in Category I areas are seismically analyzed and supported for SSE conditions so that their failure will not damage safety-related equipment. For containment penetrations, see Section 3.2.

Operational Design Basis

The breathing air system has been designed to provide air suitable for breathing at selected breathing air stations for use by unit personnel during potential or actual airborne contamination situations.

9.3.1.3.2 System Description

Compressed air is supplied to the breathing air system by an
23 oilfree reciprocative air compressor (Figure 9.3-3). The
compressor is designed with a capacity of 250 scfm at 85 psig discharge pressure and is equipped with an inlet filter and aftercooler. Inlet air to the compressor is taken from outside the turbine building, compressed, cooled, and discharged via headers to two air receivers. The compressor is provided with manual and automatic starting and shutdown features.

Cooling is provided by a self-contained cooling unit that consists of a circulating pump and forced draft type radiator.

Air quality is maintained by an inline three-stage filtration unit that removes oil, water, particulates, and carbon monoxide, and delivers clean air that meets OSHA requirements for breathing air.

During normal unit power operation, breathing air piping within the primary containment will be physically disconnected by a flexible hose connection and isolated by valves inside and outside the containment.

The compressor aftercooler is a shell and tube, counterflow heat exchanger with air passing through the tubes and coolant circulating around the tubes. An integral moisture separator equipped with an automatic drain trap removes condensed moisture from the cooled air. Coolant is provided by a self-contained cooling system. The aftercooler is built to ASME Section VIII, Division 1, requirements for a design pressure of 125 psig, and is equipped with a relief valve.

The automatic depressurization system is safety-related, and all pressure-retaining components of the system are designed, constructed, and inspected in accordance with the applicable requirements of ASME Section III, Division 1, Subsection ND for Class 3 components, and Subsection NC for Class 2 components. Not included in this safety-related classification are the nitrogen gas storage tanks, equipment, and components located in the yard outside the reactor building.

Piping segments that penetrate the primary containment and serve as a containment boundary are designed to Safety Class 2, Category I requirements.

The loss of nitrogen gas for instrumentation and controls causes gas-operated valves to fail to appropriate safe positions. In the event that the nitrogen gas supply from the nitrogen gas storage tanks is lost, a 5-day supply is available to the accumulators from ADS nitrogen receiver tanks 2IAS*TK4(Z-) and 2IAS*TK5(Z-). In addition, there are provisions for recharging the ADS nitrogen receiver tanks through its individual supply lines located in a missile-protected area outside the standby gas treatment building from special emergency tube trailer supply connections. These special, emergency recharging lines are part of the GSN system and are classified Seismic Category I, Safety Class 3.

Power Generation Bases

The automatic depressurization system requires clean, dry, oilfree nitrogen gas at approximately 175 psig to be supplied to the selected group of seven main steam safety relief valves and their respective accumulators located inside the reactor primary containment. This designated group of ADS safety relief valves and accumulators is divided into two subgroups with three or four valves and accumulators in each subgroup. Each subgroup is supplied with nitrogen gas from one of two separate ADS receiver tanks. Each ADS receiver tank is supplied with nitrogen gas at 365 psig from a bank of six horizontal, high-pressure nitrogen gas storage tanks located outside the reactor building. Nitrogen gas supplied for instrumentation and controls meets or exceeds the equivalent air quality requirements established for safety-related control air systems (SRCAS) by ANSI MC11.1-1975 (approved January 15, 1976) (ISA-S7.3), Quality Standard for Instrument Air. |28

All piping, valves, and fittings associated with the automatic depressurization system are of stainless steel materials. Also, the system will be given a complete preoperational cleaning until the applicable acceptance cleanliness levels are established and verified. In addition, since the piping system materials are corrosion-resistant, the cleanliness levels achieved during preoperational cleaning are expected to be maintained and controlled to within acceptable limits.

Each of the six high-pressure nitrogen gas storage vessels is designed, fabricated, tested, and stamped in accordance with the ASME Unfired Pressure Vessel Code, Section VIII, and conforms to Code Case No. 1205 for seamless integrally forged vessels. The six-vessel modular assembly is provided with manifold isolation valves which separate three active vessels and three reserve vessels. A fill stanchion is provided for refueling from a high-pressure tube trailer.

9.3.1.4.2 System Description

The automatic depressurization system is supplied with nitrogen gas from a bank of six horizontal, high-pressure nitrogen gas storage tanks located outside the reactor building. Nitrogen gas is supplied to two ADS nitrogen receiver tanks at 365 psig. Each ADS nitrogen receiver tank supplies nitrogen gas to its corresponding subgroup of either three or four ADS valves and accumulators through a 365/185 psig pressure reducing station. These two ADS nitrogen receiver tanks provide makeup nitrogen to compensate for valve leakage losses and to maintain the required pressure at the accumulators.

A diaphragm-type ADS air compressor is provided to supply instrument quality air for testing purposes, if desired, during plant shutdown and maintenance periods. Its discharge air supply connection is valved off during normal plant operation.

9.3.1.4.3 Safety Evaluation

The two ADS nitrogen receiver tanks supplied by the bank of six horizontal nitrogen gas storage tanks will operate to
23 maintain the required ADS valve accumulator pressure of 175 psig.

Each nitrogen gas accumulator provides a passive safeguard which automatically supplies a motive source for the operation of each SRV in the automatic depressurization system. The failure of a pilot control valve in the valve actuators can only affect a single SRV. This is due to the independence of the other, and a postulated single failure does not prevent the operation of the remaining units. The

2. Open (red) and closed (green) indicating lights for the following:

   a. ADS primary containment isolation valves.

   b. ADS header high flow valves.

   c. ADS header low flow valves.

3. Inoperable (amber) indicating lights for the following:

   a. ADS isolation valves bypass/inoperable.

   b. ADS control valve power failure.

   c. ADS systems manually out of service.

4. Position off-normal (white) indicating lights for the ADS primary containment isolation valves.

5. Pressure indicators for the following:

   a. ADS nitrogen supply headers.

   b. ADS nitrogen receiver tanks.

6. Annunciators for the following:

   a. ADS air compressor auto trip/fail to start (not used during normal plant operation).

   b. ADS air compressor auto start (not used during normal plant operation).

   c. Primary containment isolation valve power failure.

   d. ADS supply nitrogen systems bypassed or inoperable.

   e. Keylock LOCA override.

   f. ADS trouble.

   g. ADS nitrogen supply header pressure low.

   h. ADS primary containment manual isolation.

9.3.1.5 Instrument Nitrogen System

9.3.1.5.1 Design Bases

Safety Design Basis

Instrumentation and control systems located inside the reactor primary containment are supplied with nitrogen gas at 120 psig from the instrument nitrogen system (GSN). The IAS designation is retained for these systems which are nitrogen gas exclusively during normal plant operation.

Instrumentation and control systems located inside the reactor primary containment, except as described in Section 9.3.1.4.5, are not safety related. However, all piping, valves, and fittings located in Category I areas are seismically analyzed and supported in accordance with safe shutdown earthquake (SSE) design requirements so that their failure will not damage safety-related equipment. For containment penetrations and items within the containment areas, see Section 3.2.

Power Generation Design Bases

Nitrogen gas for instrumentation and control systems located inside the reactor primary containment areas is supplied from the vapor spaces of two 11,000-gal liquid nitrogen vertical storage tanks maintained under a constant pressure of approximately 200 psig. The liquid nitrogen tanks are located in the yard area, north-northeast of the reactor building, alongside the railroad access lock. From the liquid nitrogen tanks nitrogen flows through an active bank of finned ambient vaporizers, a trim heater for heating to 70°F, and a 200/120 psig pressure-reducing station. An instrument nitrogen receiver is provided inside the reactor building for additional storage capacity. Nitrogen gas for instrumentation and controls inside the primary containment is distributed from this nitrogen receiver.

A nitrogen gas backup supply connection is provided from the high-pressure nitrogen gas storage cylinders to the
26 | instrument nitrogen receiver through a 365/100 psig pressure-reducing station.

Although instrumentation and control systems within the reactor primary containment are nonsafety-related, the nitrogen gas supplied for these systems meets or exceeds the quality requirements of ANSI MC11.1-1975 (approved January 15, 1976) (ISA-S7.3), Quality Standard Instrument Air, for use with safety-related control air systems (SRCAS). Additionally, these piping systems will receive a preoperational cleaning for the removal of contaminants and to provide the required cleanliness level required. Also, all piping associated with these systems is of stainless steel, which eliminates the potential for particulate contamination coming from the piping material.

The pressure-retaining components of the instrumentation and control systems located inside the reactor primary containment are designed, constructed, and inspected in accordance with the applicable requirements of ASME Section III, Division 1, Subsection ND for Class 3 components, and Subsection NC for Class 2 components. Piping segments that penetrate the primary containment boundary are designed to Safety Class 2, seismic Category I requirements.

Each 11,000-gal liquid nitrogen storage tank contains the equivalent gas capacity of 1,024,000 SCF of nitrogen. Each storage vessel consists of a Type 304 stainless steel inner tank fabricated to Section VIII of the ASME Code requirements, an outer carbon steel jacket, and an annular space under vacuum filled with superinsulation for maintaining a low normal evaporation rate of approximately 0.15 percent per day. The normal operating pressure of the liquid nitrogen storage tank is 200 psig.

9.3.1.5.2 System Description

The nitrogen gas supply for instrumentation and controls within the reactor primary containment areas is provided by the two 11,000-gal liquid nitrogen vertical storage tanks
located in the yard area (see Figure 9.3-20 for system 23
P&IDs). These two liquid nitrogen storage tanks also supply nitrogen gas for inerting the primary containment when required. Additionally, a low-pressure slipstream from the nitrogen gas system maintains the reactor primary containment atmosphere inerted during normal plant operations. A nitrogen gas backup connection to the instrument nitrogen system is provided from the high pressure nitrogen gas storage cylinders through a 365/100 psig pressure-reducing station during off-normal conditions for instrument nitrogen supply.

The nitrogen gas supply for instrumentation and controls is normally drawn off the vapor spaces of the liquid nitrogen storage tanks, absorbs heat energy from the surrounding environment across an active bank of finned ambient vaporizers, heated to 70°F through one of two electric trim heaters, and its pressure reduced from 200 psig to 120 psig.

The instrument nitrogen system is provided with all necessary pressure and temperature indicators, alarms, and safety relief devices for safe and reliable operation. A solenoid-operated temperature control valve installed in the main supply header is set to close if the nitrogen gas temperature drops to the low temperature setpoint. This is a safeguard feature that prevents the flow of low temperature nitrogen gas into the piping distribution system in the event of a trim heater failure.

An instrument nitrogen receiver is provided inside the reactor building for additional storage capacity. Nitrogen gas is distributed throughout the instrumentation and control systems piping network within the reactor primary containment areas from this receiver.

9.3.1.5.3 Safety Evaluation

The station nitrogen systems operate to supply the instrumentation and control systems inside the reactor primary containment with instrument quality nitrogen gas at 120 psig.

The liquid nitrogen storage tanks and the six modular nitrogen gas cylinders, nitrogen gas receivers, and accumulators have sufficient capacities to supply the requirements of the instrumentation and control systems within the reactor primary containment.

The principal gas-operated valves supplied with instrument nitrogen gas inside the primary containment areas are the 28 inboard main steam isolation valves, the main steam safety relief valves, and the drywell vacuum breakers. The selected main steam safety relief valves in the automatic depressurization system (ADS) are independently supplied with nitrogen gas from the high pressure nitrogen gas storage cylinders described in the previous section, Section 9.3.1.4.

Each accumulator in the instrument nitrogen system provides a passive safeguard which automatically supplies a motive power source for the operation of each safety relief valve. The failure of a pilot control valve in the valve actuators is limited to that particular single safety relief valve, as each SRV is independent of the others; and a postulated single failure does not interfere with the operation of the remaining units. The design bases covering the total number of safety relief valves include additional allowances for the malfunction of any one valve.

The failure modes and effects analysis (FMEA) of the instrument nitrogen systems, as part of the overall instrument air systems, is provided in the Nine Mile Point Unit 2 FSAR FMEA Report.

To prevent introducing cold (less than 40°F) nitrogen into the primary containment, the nitrogen temperature, for normal inerting, is controlled to 70°F and monitored upstream of the normal vent and purge lines. Low nitrogen temperature (55°F) is alarmed in the control room. Should the temperature continue to fall to 40°F at the outlet of the vaporizer, an independent temperature device will trip the outlet control valve closed. The nitrogen supply to the instrument nitrogen system is fed from nitrogen storage bottles and the ambient vaporizer is followed by trim heaters to hold the temperature at 70°F. The supply is fed to an accumulator prior to any containment penetration, thus essentially precluding any cold nitrogen from entering the containment. In addition, a temperature sensing device just downstream of the trim heater will trip the downstream valve closed if the temperature drops below 40°F. In addition, there is no equipment or piping in the direct path of the injected nitrogen in either the drywell or wetwell, and the nitrogen system is normally isolated from the primary containment. Inerting is controlled administratively, and the valves are returned to a closed position after inerting.

9.3.1.5.4 Inspection and Testing Requirements

The instrument nitrogen system is operated on a continuous basis. It is maintained and monitored, with off-normal conditions alarmed during normal plant operation.

The instrumentation and control systems within the reactor primary containment will be tested in accordance with the requirements of the applicable regulatory positions of Regulatory Guide 1.68.3, as discussed in Table 1.8-1. 26

9.3.1.5.5 Instrumentation Requirements

<u>Description</u>

Instrumentation and controls are provided for the manual and automatic operation of the nitrogen instrument systems within the reactor primary containment areas. These controls and monitors are described below.

The nitrogen gas system is placed in operation manually, including the trim heaters. In normal operation only one of two trim heaters is used to control the nitrogen gas temperature. The other trim heater is held on standby.

The instrument nitrogen systems primary containment isolation valves close when any of the following conditions exist: the control switch is in the normal closed position, a LOCA isolation signal is present, and the manual isolation switch is activated. The isolation valves can be manually opened when a LOCA isolation signal is not present and the manual isolation switch is not activated.

Monitoring

Control room indications are provided for the following functions:

1. Open (red) and closed (green) indicating lights for the instrument nitrogen system primary containment isolation valves.

2. Position off-normal (white) indicating lights for the instrument nitrogen system primary containment isolation valves.

3. Annunciators for the following:

    a. Primary containment isolation valve power failure.

    b. Keylock LOCA override.

    c. Instrument nitrogen system trouble.

    d. Instrument nitrogen system primary containment manual isolation.

High temperature samples (steam samples or liquid samples at temperatures greater than 180°F) are condensed and/or subcooled using local (close to the sample source) coolers. These coolers are Type 316 stainless steel and are rated at 5,000 psig at 1,000°F. Their maximum working conditions exceed the design conditions of all sample sources.

All samples entering the sample panels are cooled sufficiently to ensure operator safety. Each sample line has an air-operated isolation valve (AOV) close to the sample source. These AOVs are manually activated by pneumatic valves from the sample panel. In the reactor and turbine sample systems, the high temperature samples have temperature switches that will automatically close the AOV if the sample temperature in the panel exceeds 180°F. In the radwaste sample system, flow switches are installed on the outlet cooling water lines for the sample coolers. The 23
flow switches will close the sample line isolation AOVs if low cooling water flow is sensed. All AOVs fail closed upon loss of control power or air supply pressure. Manually operated, rod-in-tube pressure-reducing valves reduce any residual high sample pressure in the sample panel. Manual needle or globe valves regulate final grab sample flow. To ensure proper temperature compensation of conductivity measurements, conductivity samples are conditioned to 77 ±1°F by a constant temperature bath prior to inline analysis. Suitable panel instrumentation is provided to allow proper sample system operation and to ensure the safety of the operator. Grab sample sinks have ventilated fume hoods to collect any airborne contamination. All sample panels are located in low radiation areas to reduce operator exposure. All liquid sample drainage is directed 23
to the respective building equipment drain system or is collected and returned to the plant.

To provide representative samples, all sample lines are sized to maintain Reynolds numbers in excess of 4,000 (fully turbulent flow). Sample tubing runs are as short as possible and are sized to allow the highest practicable velocities. All tubing enters the top of the sample panel, thereby allowing the final leg of tubing to be downward in direction. To minimize coolant loss in case of a leak, tubing with an internal diameter of 0.18 in (reactor and turbine sample systems) and 0.209 in (radwaste sample system) is used. The tubing is ASTM A213 Grade Type 316 stainless steel rated at 4,261 psig at 1,000°F. These maximum working conditions exceed the design condition of all sample sources. Incoloy 825 tubing is used on the radwaste evaporator sample lines. This material was selected due to its corrosion resistance to sodium sulfate solution being sampled.

Parent process piping is fitted with sample probes or wall taps in turbulent flow zones to ensure representative samples. All continuous samples have bypass purge lines around the analyzers. Grab samples are purged to hooded sinks.

9.3.2.3 Safety Evaluation

The process sampling systems are not required to function during or following an accident, nor are they required to safely shut down the reactor.

9.3.2.4 Inspection and Testing Requirements

Nearly all process sampling system components are used regularly during power operation or during shutdown, thereby providing continuous assurance of system availability and performance. Routine calibration checks are performed on the continuous analyzers to ensure accurate indications and alarm functions.

9.3.2.5 Instrumentation Requirements

9.3.2.5.1 Reactor Plant Sample System

Description

Instruments and controls are provided to monitor the quality of reactor coolant and various reactor plant fluid systems. The controls described below are situated locally. Except where noted, the monitors described below are located in the main control room. The control logic is shown on Figure 9.3-6.

Operation

23 Temperature and flow rate indicators are provided on the sample panel in the reactor building to indicate that samples are properly conditioned for sampling purposes.

Sample valves for sampling lines are opened and closed manually. The sample valves for the RHR heat exchangers and the reactor recirculation inlet samples automatically trip closed on high sample temperature to prevent excessive downstream temperature in the sample line.

The diesel generator building drain sump pumps discharge to the storm sewer through the diesel generator yard area oil separator by a hand-operated valve. 27

Monitoring

Reactor Building Equipment and Floor Drains

Recorders are provided for:

1. Drywell floor drain tank level.
2. Drywell floor drain pump flow.
3. Drywell floor drain leak rate.
4. Drywell equipment drain tank level.
5. Drywell equipment drain pump flow.
6. Drywell equipment drain leak rate.

Alarms are provided for:

1. Reactor building floor drain leakage high.
2. Reactor building floor drain temperature high.
3. Drywell floor drain tank level high-high.
4. Drywell floor drain containment isolation valves inoperable.
5. Drywell floor drain leakage rate high.
6. Drywell floor drain daily leakage rate high.
7. General area, HPCS, LPCS, RHR-A, RHR-B, RHR-C, and RCIC pump rooms flood water level high.
8. Reactor building floor drain system trouble.
9. Reactor building equipment drain tank leakage high.
10. Drywell equipment drain containment isolation valves inoperable.
11. Drywell equipment drain tank temperature high.
12. Drywell equipment drain leakage rate high.

13. Drywell equipment drain daily leakage rate high.

14. Drywell equipment drain tank level high-high.

15. Reactor building equipment drains system trouble.

16. Reactor water drain valves not closed.

17. Drywell floor drain containment isolation valve motor overload.

22 18. Drywell equipment drain containment isolation valve motor overload.

19. Drywell floor drain pump motor overload.

20. Drywell equipment drain pump motor overload.

21. Cubicles 2RHS*E1A and *E1B flooded.

<u>Turbine Building Equipment and Floor Drains</u>

Alarms are provided for:

1. Turbine building floor drains leakage high.

2. Turbine building floor drains system trouble.

3. Turbine building equipment drains leakage high.

4. Turbine building equipment drain system trouble.

<u>Radwaste Building Equipment and Floor Drains</u>

Alarms are provided for:

1. Radwaste building equipment and floor drains leakage high.

2. Radwaste building equipment and floor drain system
22 trouble.

<u>Miscellaneous Buildings Equipment and Floor Drains</u>

Alarms are provided for:

22 1. Screenwell building floor and equipment drains leakage high.

22 2. Screenwell building floor drain sump 5 level high.

minates the nuclear fission chain reaction in the uranium fuel. The specified neutron absorber solution is sodium pentaborate ($Na_2B_{10}O_{16} \cdot 10H_2O$). It is prepared by dissolving stoichiometric quantities of borax and boric acid in demineralized water. An air sparger is provided in the tank for mixing. To prevent system plugging, the tank outlet is raised above the bottom of the tank.

The SLC system can deliver enough sodium pentaborate solution into the reactor (Figure 9.3-18) to assure reactor shutdown. This is accomplished by filling the SLC storage tank with dimineralized water to the low level alarm point, and then adding sodium pentaborate. The solution can be diluted with water to within 6 in of the overflow level volume to allow for evaporation losses or to lower the saturation temperature. The tank may contain boron solution from a minimum volume of 4,418 gal (net low level volume) to a maximum of 4,815 gal (net high level volume) based on a zero level of 5.1 in above the centerline of the outlet.

The minimum temperature of the fluid in the tank and piping is consistent with that obtained from Figure 9.3-19 for the solution temperature. The saturation temperature of the recommended solution is 60°F at the low level alarm volume. 27
Equipment containing the solution is installed in an area in which the air temperature is maintained within the range of 70°F to 100°F. An electrical resistance heater system provides a backup heat source that maintains the solution temperature between 75°F (automatic operation) and 85°F (automatic shutoff) to prevent precipitation of the sodium pentaborate from the solution during storage. High or low temperature, or high or low liquid level, causes an alarm in the main control room. The entire system is located within the reactor building, so it is unaffected by cold weather.

The positive displacement pumps are sized to inject the boron solution (minimum 41.2 gpm per pump) into the reactor within a specified time period, independent of the amount of solution in the tank.

The pump and system design pressure between the explosive valves and the pump discharge is 1,400 psig. The two relief valves are set to open at 1,387 psig with no back pressure. To prevent bypass flow in the event that a pressure relief valve fails and opens, a check valve is provided downstream of each relief valve in each pump discharge line.

The two explosive-actuated injection valves provide assurance of opening when needed and ensure that boron does not leak into the reactor even when the pumps are being tested. Each explosive valve is closed by a shear plug in the inlet chamber. The plug is circumscribed with a deep groove so the end readily shears off when pushed with the valve plunger. This opens the inlet hole through the plug. The sheared end is pushed out of the way in the chamber and is shaped so it does not block the ports after release.

The shearing plunger is actuated by an explosive charge with dual ignition primers inserted in the side chamber of the valve. Ignition circuit continuity is monitored by a trickle current, and an alarm occurs in the control room if either circuit opens. Indicator lights show which primary circuit opened.

Signals from the RRCS can automatically initiate the SLCS by
actuating both loops. The SLC system can also be actuated
manually by two keylocked spring-return switches which
18 ensure that switching from the NORMAL position to RUN
position is a deliberate act. Operation of either switch
starts an injection pump and simultaneously opens its
respective explosive valve and storage tank outlet valve.
The initiation generates a signal to close the reactor water cleanup system isolation valve to prevent loss or dilution of the boron. This isolation signal is sealed-in during SLC operation and remains sealed-in until reset by operator action.

A light in the control room indicates that power is available to the pump motor contactor and that the contactor is deenergized (pump not running). Another light indicates that the contactor is energized (pump running).

Storage tank liquid level, tank outlet valve position, pump
18 discharge pressure pump flow, and loss of continuity of the
explosive valves indicate that the system is functioning.
18 Pump discharge, pump flow, and valve status are indicated
in the main control room.

Equipment drains and tank overflow are not piped to the radwaste system but to a separate container (such as a 55-gal drum) that can be removed and disposed of independently to prevent any trace of boron from inadvertently reaching the reactor.

Table 9.3-2 contains the process data for the various modes of operation of the SLC system. Seismic category and safety class are included in Table 3.2-1. Principles of system testing are discussed in Section 9.3.5.4.

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The SLC equipment required for injection of neutron absorber solution into the reactor is designed as Category I for withstanding the specified earthquake loadings (Chapter 3). The system piping and equipment are designed, installed, and tested in accordance with requirements stated in
26 Section 3.9B.

The SLC system is powered normally from offsite power sources. In the event of a plant offsite power failure, the pumps, valves, and controls necessary to assure boron injection are powered from the standby diesel generators. The heaters are manually connectable to the standby diesel generators. The pumps and valves are powered and controlled from separate divisional buses and circuits.

The SLC pumps have sufficient pressure margin, up to the system relief valve setting of 1,387 psig with no back pressure to assure solutioninjection into the reactor above the normal pressure in the bottom of the reactor. The reactor safety relief valves begin to relieve pressure above approximately 1,100 psig. Therefore, the SLC positive displacement pumps cannot overpressurize the nuclear system.

Only one of the two standby liquid control loops is needed for backup shutdown system operation. If a redundant component (e.g., pump) in one of the two parallel loops is found to be inoperable, there is no immediate threat to shutdown capability, and reactor operation can continue during repairs. The time during which one of the two parallel loops may be out of operation is given in the Technical Specifications.

9.3.5.4 Testing and Inspection Requirements

Testability of one pump at a time is possible while the reactor is in service. While one pump is being tested during reactor operation, the other pump is capable of in-